APPENDIX G

ACCOUNTING OF TRANSPORTATION EMISSIONS

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ACCOUNTING OF TRANSPORTATION EMISSIONS

G.1 Introduction

The complete evaluation of the biomass-ethanol and crude oil-reformulated gasoline energy cycles requires an evaluation of the emissions from multiple internal combustion engine-powered (ICE-powered) transportation modes (i.e., personal commuter vehicles, farm equipment, material handling equipment, trucks, rail, inland barge, and ocean barge/tanker, and pipeline) and five fuel types (i.e., reformulated gasoline, E-95, No. 2 diesel fuel, No. 6 diesel fuel, and electricity). Presented in Figure G.1 are the transportation modes and fuel types used in each stage of the biomass-ethanol and crude oil-reformulated gasoline energy cycles.

This appendix addresses the approach used to consistently quantify the emissions from the ICE-powered product transportation vehicles and special use vehicles. Emissions associated with end-use of ethanol and reformulated gasoline in personal commuter vehicles are discussed in Appendix E. All pipeline transportation is assumed to be electrically-powered with no direct emissions. (Pipeline electricity consumption is discussed in Appendixes D and F under the topics of ethanol distribution, and crude oil-reformulated gasoline transportation, respectively.)

The transportation methodology is outlined in Sections G.3 and G.4 of this appendix. Section G.3 addresses typical product transportation vehicles including trucks, trains, inland barges, and ocean barges & tankers. Section G.4 describes the methodological approach used to address special-use vehicles, such as farm equipment and various loading equipment. The mathematical algorithms outlined in these two sections require values for fuel constants, engine efficiencies, emission factors, etc. These values are presented in Section G.2 of this appendix.

G.2 Reference Data

G.2.1 Standard Fuel Characteristics

Throughout this energy cycle analysis the following standard fuel characteristics have been assumed:

Diesel No. 2: LHV[(a)] = 128,700 BTU/gallon
s.g.[(b)] = 0.85
density = 7.08 lbm/gallon
carbon content: 87%

Figure G-1. Transportation Modes and Fuel Types by Energy Cycle Stage

		Biomass-Ethanol Energy Cycle				**Crude Oil-Gasoline Energy Cycle**		
		Biomass Transport						
		Harvesting	To Plant	Ethanol Trans	End Use	Crude Oil Trans	Gasoline Trans	End Use
Truck	HD Diesel (Low S)	2000 (MSW)	2000 (MSW) 2010	2000 2010		2000 2010	2000 2010	
	E95		2010*	2010*				
Farm Equip.	Diesel (Low S)	2010						
	E95	2010*						
Rail	Diesel (Low S)		2000 (MSW)	2000 2010		2000 2010		
Barge	Diesel (Low S)		2010			2000 2010	2000 2010	
Pipelines	Electricity					2000 2010	2000 2010	
Auto	E10				2000			
	E95				2010			
	Reformulated Gas**							2000 2010

* Sensitivity Runs

**Different emissions in 2000 and 2010

Diesel No. 6:	LHV = 137,500 BTU/gallon s.g. = 0.96 density = 8.00 lbm/gallon carbon content: 90%
Reformulated Gasoline:	LHV = 110,600 BTU/gallon s.g. = 0.74 density = 6.16 lbm/gallon
Ethanol-10[c,d]:	LHV = 107,140 BTU/gallon s.g. = 0.75 density = 6.25 lbm/gallon
Ethanol-95[e]:	LHV = 77,730 BTU/gallon s.g. = 0.79 density = 6.58 lbm/gallon
Ethanol-100[c]:	LHV = 75,670 BTU/gallon s.g. = 0.79 density = 6.58 lbm/gallon

(a) Lower heating value (LHV).
(b) Specific gravity (s.g.).
(c) These data are shown for reference. They are not required to estimate vehicle combustion emissions.
(d) Ethanol-10 is 90% reformulated gasoline, 10% ethanol by volume.
(e) Ethanol-95 is 5% reformulated gasoline, 5% ethanol by volume.

Sources: Diesel No. 2, Diesel No. 6 and Ethanol-100 (Davis 1991). Reformulated Gasoline, Ethanol-10 and Ethanol-95 data calculated as shown below.

An estimate of the energy density of reformulated gasoline compared to conventional gasoline is given in Table G-1. The estimate ignores any nonideal volume changes on mixing, and assumes that the reformulated fuel contains 15% MTBE plus enough added alkylate to replace aromatics and olefins to the extent indicated in the table. The net result is a decrease of approximately 4 percent in the energy density.

Because of the change in reformulated gasoline energy density, the energy ratio between gasoline and alternative fuels will change. Using calculated heating values and ignoring changes in mixing volumes, heating values for ethanols blends are shown in Table G-2.

Table G-1.
Estimated Energy Density of Reformulated Gasoline

Component	Original		Reformulated	
	Vol%	BTU/Gal	Vol%	BTU/Gal
Aromatics	34.4	43,707	21.6	27,440
Olefins	9.7	9,900	5.5	5,610
Benzene	1.6	2,040	0.8	1,020
Other	54.3	59,353	54.3	59,353
MTBE	0.0	0	15.0	14,034
Added Alkylate	0.0	0	2.8	3,131
	100.0	115,000	100.0	110,588

Table G-2.
Estimated Energy Density of Ethanol Blends

Fuel	BTU/Gal	Ratio E-Blend/Gasoline
Reformulated Gasoline	110,588	--
Ethanol-10	107,140	0.97
Ethanol-95	77,730	0.70
Ethanol-100	75,760	0.69

G.2.2 Fuel Economy

This section discusses three topics: brake specific fuel consumption (bsfc); fuel economies; and vehicle efficiencies.

- **Brake specific fuel consumption** (bsfc) is the quantity of fuel consumed by a vehicle engine per unit of energy generated by the engine. In this analysis, it is expressed in the units, pounds of fuel consumed per brakehorsepower-hour generated (i.e., lb-fuel per bhp-hr). The bsfc is a measure of engine efficiency. It is independent of vehicle characteristics.

- **Fuel economy**, commonly expressed in the units "MPG", includes all inefficiencies of the vehicle (e.g., engine inefficiencies, transmission inefficiencies, drivetrain inefficiencies and vehicle drag). Fuel economies differ from the bsfc values in that the bsfc values only include engine inefficiencies.

- **Vehicle efficiency** was used in this analysis for calculating energy consumption by product transportation vehicles (i.e., barges, trucks and rail). Vehicle efficiencies are a function of the load carried and the fuel economy of the vehicle. Specifically, vehicle efficiency is a measure of the amount of energy required to move one ton of product one mile. In this analysis, it is expressed in the units BTUs per ton-mile.

Bsfc factors are presented in Table G-3. The bsfc values for ocean barges and tankers were estimated from low-speed marine diesel engine data (Sulzer Diesel 1990). Inland barges were assumed to be either self-propelled by medium-speed diesel engines or by tugboats using medium-speed diesel engines. Locomotives used in rail transportation are assumed to be powered by similar medium-speed diesel engines. The bsfc values for medium-speed diesel engines were based on Argonne National Laboratory data (1982) for medium-speed diesel engine operation in locomotives. The locomotive medium-speed diesel bsfc was applied to the inland barges based on knowledge that efficiencies of these types of engines do not vary appreciably with application. Due to the low turnover of low-speed and medium-speed diesel engines in rail, barge, and tanker applications, the bsfc is assumed constant for the period of 1990 to 2010.

Trucks are assumed to use high-speed diesel engines. The bsfcs for trucks are correlated with National Energy Strategy (NES) fuel economies. They were estimated by using the 1987 national average fuel economy for class 7 and 8 tractor/trailer combinations (MVMA 1990) as a base and projecting to the years 2000 and 2010 using NES projections (DOE 1991). The resulting fuel economies are:

1990	5.3 MPG
2000	5.7 MPG
2010	6.0 MPG

These values were then converted to bsfc values using Motor Vehicle Manufacturers Association data (MVMA 1983). As illustrated in Table G-1 the bsfc for trucks improves from 1990 to 2010 due to its correlation to the fuel economy improvement projected in the NES. The bsfc values developed for trucks were also applied to material handling equipment and agricultural equipment, because these applications also use high-speed diesel engines.

Comparable fuel economy values for ethanol-95 (E95), are based on the relative energy efficiency of the compression ignition cycle using E95. The relative energy efficiency in 1990 is similar for E95 and diesel fuel. In 2000, E95 has an overall energy efficiency gain of 5 to 6% over diesel due to an expected 2% engine efficiency advantage, and a 4% penalty for diesel engines due to the use of particulate exhaust traps (Lawson 1991). In the year 2010, improvements in diesel trap technology results in a net 4% energy efficiency advantage for E95[1]. The projected E95 fuel economies are:

1990	3.1 MPG
2000	3.5 MPG
2010	3.7 MPG

The bsfc values for ethanol trucks are presented in Table G-3.

Table G-3.
Brake Specific Fuel Consumption by Transportation Mode

Transportation Mode	bsfc (lb-fuel per bhp-hr)[a]		
	1991	2000	2010
Tanker/Ocean Barge[b]	0.28	0.28	0.28
Inland Barge	0.37	0.37	0.37
Rail	0.37	0.37	0.37
Truck[c]	0.50	0.46	0.44
Material Hndlg. Equip.	0.50	0.46	0.44
Agricultural Equip.	0.50	0.46	0.44
Ethanol Truck [d]	0.78	0.67	0.66

(a) All modes use No. 2 diesel fuel, except as noted.
(b) Uses No. 6 diesel fuel.
(c) Correlated with NES fuel economies.
(d) Uses Ethanol-95.

Sources: Tanker/Ocean Barge data (Sulzer Diesel 1990).
Rail data (ANL 1982).
Inland barge, trucks and equipment data was derived as described in text.

[1]Final performance estimates were prepared by J.E. Sinor Consultants, Inc. using the references cited in the text, the NES, and Mintz 1991.

Table G-4 presents vehicle efficiencies in the units BTU-in per ton-mile. This efficiency is the BTUs of fuel that are burned by a vehicle to move one ton of product one mile.

Table G-4.
Vehicle Efficiencies

Transportation Mode	$\frac{\text{BTU-in}}{\text{ton-mile}}$
Inland Barge	400
Rail	434
Trucks	(a)

(a) See discussion below.

Sources: Inland Barge and Rail (Davis 1991)

Vehicle efficiencies for trucks are a function of the load carried and the fuel economy. For example, a flat-bed tractor trailer hauling biomass in the year 2010 is projected to have a fuel economy of 6.0 MPG (from the discussion above). Based on a 20-ton load, a heating value for No. 2 diesel fuel of 128,700 BTU/gallon and a density of 7.08 lbm/gallon, a flat-bed tractor trailer efficiency of 1070 BTU-in per ton-mile can be calculated. Tanker trucks used to haul gasoline, E10, and E95, are assumed to have same fuel economy as flat-bed tractor trailers.

G.2.3 Emission Factors

Tables G-5 through G-10 present emission factors by engine type, duty cycle and fuel, and include the following:

- high-speed, heavy-duty engines for trucks using No. 2 diesel fuel;
- high-speed, heavy-duty engines for agricultural equipment using No. 2 diesel fuel;
- high-speed, heavy-duty engines for material handling equipment using No. 2 diesel fuel;
- high-speed, heavy-duty engines for trucks using ethanol-95;
- high-speed, heavy-duty engines for agricultural equipment using ethanol-95; and
- medium-speed engines for rail and inland barges using No. 2 diesel fuel.

Neither the EPA nor the California Air Resources Board--the most likely sources for this type of data--report any available emissions data for low-speed marine diesel engines that consume No. 2 diesel fuel. It was assumed that, the medium-speed diesel emission factors also apply to low-speed diesel applications.

Emissions factors are presented in "grams per brakehorsepower-hour" (i.e., g/bhp-hr) or "grams per pound of fuel consumed" (i.e., g/lb-fuel). The units g/bhp-hr refer to the amount of emissions released for each brakehorsepower (i.e., unit of energy) generated by a vehicle's engine. Emissions factors presented in the units g/bhp-hr are either directly based on scientific test data or extrapolated from it. As referenced in the footnotes of Tables G-5 to G-10, much of this data comes from EPA 1985. While this source contains the best data currently available, it's applicability to 1990 and future vehicles is somewhat subjective. Sulfur dioxide and carbon dioxide emissions are a function of the quantity of fuel combusted and are independent of engine type. Consequently, the emission factors for SO_2 and CO_2 are expressed in the units "g/lb-fuel".

Table G-5.
High-Speed, Heavy-Duty Engine for Trucks
Using No. 2 Diesel Fuel

	Units	1990[a]	2000	2010[b]
Exhaust VOCs[c]	g/bhp-hr	1.1	1.0	0.5
Evaporative VOCs	g/bhp-hr	nil	nil	nil
CO	g/bhp-hr	4.8	3.0	2.0
NOx	g/bhp-hr	4.8	3.8	2.0
Total PM	g/bhp-hr	0.5	0.08	0.08
CO_2	g/lb-fuel	1448	1448	1448
SO_2	g/lb-fuel	.45	0.45	0.45

(a) Based on emissions data in EPA Report AP-42.
(b) Projections based on emissions data in EPA Report AP-42, future heavy-duty diesel engine standards, and research goals now set by the engine industry (SRI 1991).
(c) Poly Nuclear Aromatic (PNA) compounds are components of diesel exhaust emissions, but they have not been sufficiently characterized to report on a quantitative basis.

Table G-6.
High-Speed, Heavy-Duty Engine for Agricultural Equipment
Using No. 2 Diesel Fuel

	Units	1990[a]	2000	2010[b]
Exhaust VOCs[c]	g/bhp-hr	1.7	1.4	1.1
Evaporative VOCs	g/bhp-hr	nil	nil	nil
CO	g/bhp-hr	3.34	4.0	4.8
NOx	g/bhp-hr	9.39	7.1	4.8
Total PM	g/bhp-hr	1.28	0.9	0.5
CO_2	g/lb-fuel	1448	1448	1448
SO_2	g/lb-fuel	.45	0.45	0.45

(a) Based on emissions data in EPA Report AP-42.
(b) Year 2010 projection based on farm tractor emissions reaching levels of high-speed, on-road engines of 1991.
(c) Poly Nuclear Aromatic (PNA) compounds are components of diesel exhaust emissions, but they have not been sufficiently characterized to report on a quantitative basis.

Table G-7.
High-Speed, Heavy-Duty Engine for Material Handling Equipment Using No. 2 Diesel Fuel[a][b]

	Units	1990[a]	2000	2010[b]
Exhaust VOCs[c]	g/bhp-hr	0.97	0.80	0.63
Evaporative VOCs	g/bhp-hr	nil	nil	nil
CO	g/bhp-hr	2.7	3.2	3.9
NOx	g/bhp-hr	8.8	6.7	4.5
Total PM	g/bhp-hr	0.81	0.57	0.31
CO_2	g/lb-fuel	1448	1448	1448
SO_2	g/lb-fuel	.45	0.45	0.45

(a) Based on emissions data in EPA Report AP-42.
(b) Year 2000 and 2010 projections based on equivalent rate of improvement projected for farm tractor emissions.
(c) Poly Nuclear Aromatic (PNA) compounds are components of diesel exhaust emissions, but they have not been sufficiently characterized to report on a quantitative basis.

Table G-8.
High-Speed, Heavy-Duty Engine for Trucks
Using E95 Fuel

	Units	1990[(a)]	2000	2010	2010[(b)]
Exhaust VOCs[(c)]	g/bhp-hr	3.5	1.5	1.0	0.3
Aldehydes	g/bhp-hr	0.25	0.15	0.10	0.05
Evaporative VOCs	g/bhp-hr	2.0	1.5	1.0	1.0
CO	g/bhp-hr	7.0	5.0	4.0	1.2
NOx	g/bhp-hr	3.5	2.5	2.0	1.5
Total PM	g/bhp-hr	0.3	0.08	0.05	0.04
CO_2	g/lb-fuel	1447	1447	1447	1447
SO_2	g/lb-fuel	0.002	0.002	0.002	0.002

(a) Based on engine test results conducted on a Detroit Diesel two-stroke engine converted for ethanol using the latest technology (Carroll 1990) and on projected improvements in technology and future emission standards.
(b) Year 2010 truck with catalytic converter.
(c) Exhaust VOC expected to consist primarily of acetaldehyde.
(d) Evaporative VOC expected to consist primarily of ethanol and denaturant (gasoline).

Table G-9.
High-Speed, Heavy-Duty Engine for Agricultural Equipment Using E95 Fuel[a]

	Units	1990[a]	2000	2010[b]
Exhaust VOCs[c]	g/bhp-hr	5.4	3.5	2.0
Aldehydes	g/bhp-hr	0.4	0.3	0.2
Evaporative VOCs	g/bhp-hr	3.0	2.0	1.0
CO	g/bhp-hr	4.9	4.0	3.0
NOx	g/bhp-hr	6.8	5.0	2.0
Total PM	g/bhp-hr	0.8	0.6	0.4
CO_2	g/lb-fuel	1447	1447	1447
SO_2	g/lb-fuel	0.002	0.002	0.002

(a) Based on engineering estimates relative to high-speed ethanol engine emission levels.

Table G-10.
Medium-Speed, Heavy-Duty Engine for Rail and Inland Barges Using No. 2 Diesel Fuel[a]

	Units	1990[a]	2000	2010[b]
Exhaust VOCs[c]	g/bhp-hr	0.5	0.4	0.3
Evaporative VOCs	g/bhp-hr	nil	nil	nil
CO	g/bhp-hr	2.0	1.5	1.0
NOx	g/bhp-hr	10.0	7.0	5.0
Total PM	g/bhp-hr	0.25	0.15	0.10
CO_2	g/lb-fuel	1448	1448	1448
SO_2	g/lb-fuel	.45	0.45	0.45

(a) Based on emissions data from Wakenell (1991) and on projected emission trends (Winner 1991).
(b) Poly Nuclear Aromatic (PNA) compounds are components of diesel exhaust emissions, but they have not been sufficiently characterized to report on a quantitative basis.

G.3 Transportation Methodology: Typical Product Transportation Vehicles

Addressed in this section is the methodology used to evaluate trucks, including:

- MSW transportation trucks;
  (transfer station to separation facility and separation facility to ethanol plant)
- agricultural biomass transportation trucks; and
- fuel transportation trucks; along with

Trains/Inland Barges/Ocean Barges & Tankers, including

- agricultural biomass transportation inland barges;
- agricultural biomass transportation trains;
- MSW transportation trains;
- fuel transportation trains;
- fuel transportation inland barges; and
- fuel transportation ocean barges & tankers.

The fundamental equation involved in the approach is as follows:

$$\frac{\text{gms of emissions}}{\text{bhp-hr}} * \frac{\text{bhp-hr}}{\text{ton-mile}} * \text{ton-miles} = \text{gms of emissions}$$

In the remainder of this appendix this equation is referred to as the "general emissions equation."

Explanatory notes on this equation and its application follow.

1. The first term in the equation,

$$\frac{\text{gms of emissions}}{\text{bhp-hr}}$$

refers to the grams of emissions per brakehorsepower-hour generated by the engine used in the transportation vehicle. This emission factor varies with engine type, duty cycle, and fuel. Emission factors are summarized in Section G.2.

2. The second term in the equation,

$$\frac{\text{bhp-hr}}{\text{ton-mile}}$$

is the amount of energy required to haul one ton of product one mile. The denominator ton-mile <u>should not</u> be confused with units of energy (e.g., lb-ft or more commonly ft-lbs). The factor "bhp-hr per ton-mile" varies with vehicle type. The appropriate factors for each vehicle type are summarized in Section G.2.

3. The third term in the equation,

ton-miles

is the total tons shipped by a given mode times the total miles traveled. For example, if 20 tons of agricultural biomass is transported via rail over a 200 mile distance, the ton-miles is 4000.

G.3.1 Trucks

A subset of "typical product transportation vehicles" is trucks.

The approach described below has been used throughout the energy cycle analysis. However, the specific application of the approach differs slightly depending on truck type (i.e., flat-bed/box trailer or tanker truck) and form of source data that is available for each truck type. The differences are outlined below.

For MSW hauling and agricultural biomass hauling trucks, an average load of 20 tons is assumed, along with the use of a heavy-duty, high-speed engine. Based on the fuel economies presented in Section G.2 and the brake specific fuel consumption for trucks presented in Table G-3, the general emission equation shown below

$$\frac{\text{gms of emissions}}{\text{bhp-hr}} * \frac{\text{bhp-hr}}{\text{ton-mile}} * \text{ton-miles} = \text{gms of emissions}$$

can be reduced to:

$$\frac{\text{gms of emissions}}{\text{mile}} * \text{miles} = \text{gms of emissions}$$

Similarly, the emission factors for trucks shown in Tables G-5 and G-8 can be converted to a "gms of emissions per mile-basis." The results of this conversion are shown in Tables G-11 and G-12. Using the equation above, and the emission factors in Tables G-11 and G-12, the total emissions for any truck scenario based on a 20-ton load can be calculated.

In the case of tanker trucks and tanker wagons, rather than explicitly calculating the inputs to the general emission equation:

$$\frac{\text{gms of emissions}}{\text{bhp-hr}} * \frac{\text{bhp-hr}}{\text{ton-mile}} * \text{ton-miles} = \text{gms of emissions}$$

the equation was simplified to the following:

$$\frac{\text{gms of emissions}}{\text{bhp-hr}} * \frac{\text{bhp-hr}}{10^9 \text{ BTUs transported}} = \text{gms of emissions}$$

This approach was taken because source data was readily obtained and easily converted to the units of the second term in this equation, "bhp-hr per 10^9 BTU transported."

Table G-11.
High-Speed, Heavy-Duty Engine for Trucks with 20-ton Load
Using No. 2 Diesel Fuel

	Units	1990[a]	2000	2010[b]
Exhaust VOCs[c]	g/mile	2.96	2.7	1.3
Evaporative VOCs	g/mile	nil	nil	nil
CO	g/mile	12.9	8.1	5.4
NOx	g/mile	12.9	10.2	5.4
Total PM	g/mile	1.35	0.22	0.22
CO_2	g/mile	1940	1796	1709
SO_2	g/mile	0.61	0.56	0.54
fuel consumed[b]	lb/mile	1.34	1.24	1.18

(a) Calculated using the emission factor with the units "g/lb-fuel" and the a fuel economy with the units lb-fuel/mile."
(b) Direct unit conversion from the units "MPG."

G.3.2 Trains/Inland Barges/Ocean Barges & Tankers

A second subset of "typical product transportation vehicles" is inland barges, ocean barges/tankers, and trains. Emissions from these transportation modes were assessed in a similar manner to trucks using the general form of the emissions equation.

In the MSW and agricultural biomass segment of the analysis, the "ton-miles" required for each product shipped was estimated and used with the emission factors (gms of emissions per bhp-hr) from Table G-10 for medium-speed diesel engines and vehicle efficiencies (i.e., bhp-hr/ton-mile) from Table G-4 to calculate total emissions. The equations used to perform the necessary calculations are outlined below.

Table G-12.
High-Speed, Heavy-Duty Engine for Trucks with 20-ton Load
Using E95 fuel

	Units	1990(a)	2000	2010(b)
Exhaust VOCs(c)	g/mile	29.42	4.04	0.81
Aldehydes	g/mile	0.67	0.40	0.13
Evaporative VOCs	g/mile	5.38	4.04	2.69
CO	g/mile	18.83	13.45	3.23
NOx	g/mile	9.42	6.73	4.04
Total PM	g/mile	0.08	0.22	0.11
CO_2	g/mile	3068	2720	2576
SO_2	g/mile	0.004	0.004	0.004
fuel consumed(b)	lb/mile	2.12	1.88	1.78

(a) With catalyst.
(b) Calculated using the emission factor with the units "g/lb-fuel" and the a fuel economy with the units lb-fuel/mile."
(c) Direct unit conversion from the units "MPG."

Ocean barges/tankers use low-speed diesel engines combusting No. 6 diesel, however, discussions with EPA's Office of Mobile Sources and the California Air Resources Board indicate that no specific emissions data for this barge configuration is available. Consequently, medium-speed diesel emission factors were used along with the same emissions estimating equations.

$$\frac{\text{gms of emissions}}{\text{bhp-hr}} * \frac{\text{bhp-hr}}{\text{ton-mile}} * \text{ton-miles} = \text{gms of emissions}$$

Total fuel consumption is estimated by applying the following equation:

$$\frac{\text{lb-fuel}}{\text{bhp-hr}} * \frac{\text{bhp-hr}}{\text{ton-mile}} * \text{ton-miles} = \text{lbs of fuel consumed.}$$

SO_2 and CO_2 are estimated with the following equation:

$$\frac{\text{lb-}CO_2 \text{ or } SO_2}{\text{lb-fuel}} * \text{lbs of fuel consumed} = \text{lbs of } CO_2 \text{ or } SO_2$$

Transportation of fuel (i.e., crude oil, E10, E95, and gasoline) was calculated based upon the general emissions equation as shown below:

$$\frac{\text{gms of emissions}}{\text{bhp-hr}} * \frac{\text{bhp-hr}}{\text{ton-mile}} * \text{ton-miles} = \text{gms of emissions}$$

This equation was simplified to the following:

$$\frac{\text{gms of emissions}}{\text{bhp-hr}} * \frac{\text{bhp-hr}}{10^9 \text{ BTUs transported}} = \text{gms of emissions}$$

This approach was taken because source data for fuel transportation was readily available and easily converted to the form of the second term in the equation, "bhp-hr per 10^9 BTU transported."

G.4 Transportation Methodology: Special-use Vehicles

This section describes the methodological approach used to address special-use vehicles which include:

- MSW collection garbage trucks,
- MSW transfer station loading equipment,
- MSW separation facility loading equipment,
- ethanol facility bulk feedstock handling equipment, and
- farm equipment.

The approach presented here for special-use vehicles is consistent with the above approach for product transportation vehicles; however, it is tailored to address the unique operating characteristics of farm equipment, MSW collection and loading equipment, and ethanol plant feedstock handling equipment. The equation for calculating emissions is as follows:

$$\frac{\text{gms of emissions}}{\text{bhp-hr}} * \text{bhp-hr} = \text{gms of emissions}$$

1. The first term of the equation,

$$\frac{\text{gms of emissions}}{\text{bhp-hr}}$$

is the appropriate emissions factor from Tables G-5, G-6 or G-7 were used, as relevant. (Garbage truck emissions were based on the emission factors for high-speed, heavy-duty diesel engines shown in Table G-5.

2. The second term of the equation,

bhp-hr

is the amount of energy expended to perform the job at hand. For example, the amount of energy to apply a ton of fertilizer or the amount of energy to collect a ton of MSW. Bhp-hr is measured at the drive shaft. This variable was calculated for each activity within each segment of the energy cycle analysis and is documented in the relevant sections of each appendix.

Total fuel consumption for special-use vehicles was estimated by applying the following equation:

$$\frac{\text{lb-fuel}}{\text{bhp-hr}} * \text{bhp-hr} = \text{lbs of fuel consumed.}$$

The factor "lb-fuel/bhp-hr" is shown in Table G-3.

SO_2 and CO_2 are estimated with the following equation:

$$\frac{\text{lb-CO2 or SO2}}{\text{lb-fuel}} * \text{lbs of fuel consumed} = \text{lbs of } CO_2 \text{ or } SO_2$$

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APPENDIX H

ENVIRONMENTAL FACTORS ASSOCIATED WITH ELECTRICITY INPUTS

APPENDIX H

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APPENDIX H

ENVIRONMENTAL FACTORS ASSOCIATED WITH ELECTRICITY INPUTS

H.1 Introduction

The biomass-ethanol and crude oil-reformulated gasoline energy cycles differ in the amount of electricity used in the stages of their cycles which include raw material extraction, material transportation, transformation (to a refined fuel), and fuel distribution. For instance, to produce and combust enough reformulated gasoline to travel one billion vehicle miles in 2010, over 30 million kilowatt hours (kWh) of electricity are needed (approximately half of which is used in the gasoline distribution stage, and the rest in the refining, crude transportation and crude production stages.) In contrast, enough electricity is produced via cogeneration in the biomass-ethanol conversion stage to not only offset the electricity demands by the both the conversion process and the biomass production and transportation stages, but also to produce a net surplus of electricity of over 35 million kWh.

The environmental emissions associated with this difference in electricity consumption can be accounted for by introducing factors that indicate how much pollution is created per unit of electricity generation. Table H.1 summarizes the results of applying such factors to the electricity consumption/generation estimates for reformulated gasoline and ethanol, over their entire energy cycles for a billion miles of vehicle travel. The pollution produced per unit of electricity generation differs among regions of the country (because every region has a unique mix of generating technologies, each of which has a different set of environmental emissions). The regional scenarios shown in Tables H.1a and H.1b demonstrate the potential range of environmental benefits associated with the electricity surplus produced by the biomass-ethanol scenarios. Table H.1a presents the incremental amount of emissions associated with secondary electricity consumption/generation. Positive values indicate that there is a net increase in emissions for a particular energy cycle scenario (e.g., year 2000 reformulated gasoline). Negative values indicate that there is a net decrease in emissions for a particular energy cycle scenario (e.g., year 2010 Tifton).[1] Table H-1b presents the total emissions and wastes associated with the entire primary energy cycle plus secondary electricity consumption/generation emissions.

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[1] The electricity surplus produced by the biomass-ethanol energy cycle would result in reduced level of electricity production via the more traditional means in the region, resulting in a reduction in pollution. Even if it is assumed that the surplus electricity is not sold to the electricity grid and therefore, is not used to supplant traditionally-generated electricity, the biomass-ethanol energy cycle still provides a considerable environmental benefit because the biomass-ethanol cycle does not require any electricity from the grid. Therefore, the minimum environmental benefit of the biomass-ethanol cycle is that it eliminates the environmental pollutants associated with electricity used in the crude oil-reformulated gasoline cycle (shown in Table H.1a).

Table H-1a.
Emissions & Wastes Associated with Secondary Electricity Generation (tons)

	2000		2010					
	Ref Gas	Chicago	Ref. Gas	Rochester	Tifton	Peoria	Lincoln	Portland
SO_2	71	92	50	-46	-87	-125	-92	-8
NO_x	63	75	54	-57	-63	-103	-118	-87
PM	5	5	4	-12	-6	-4	-5	-3
CO_2	22700	27200	20400	-21800	-24000	-31400	-32000	-16900
Solid Wastes	3800	4600	3500	-3100	-5100	-6200	-6300	-2900

Table H-1b.
Total Emissions & Wastes Associated with Energy Cycle Including Secondary Electricity Generation (tons)

	2000		2010					
	Ref Gas	Chicago	Ref. Gas	Rochester	Tifton	Peoria	Lincoln	Portland
SO_2	174	145	144	-6	-57	-82	-48	16
NO_x	665	690	415	333	308	274	276	247
PM	10	16	9	50	54	58	57	74
CO_2	380000	416000	340000	10900	2300	-3600	1900	-600
Solid Wastes	4600	11700	4200	17200	12900	14100	22200	13500

This appendix describes the computation of the regional environmental factors associated with electricity that support the results shown in Tables H.1a and H.1b. Section H.2 provides a general overview of the methodological approach to computing and applying the factors. Section H.3 gives more detail on the data sources for the regional air, water, and waste factors. Section H.4 explains the way in which factors were weighted for use in the crude oil-reformulated gasoline energy cycle.

H.2 Overview of Methodology

The environmental factors included in the analysis of electricity impacts are: air pollutant emissions (including, sulfur dioxide [SO_2], nitrogen oxides [NO_x], and total suspended particulates [TSP]), carbon dioxide [CO_2] emissions, and solid waste volumes. Factors were initially computed in terms of pounds of emissions (or wastes) per megawatt-hour (MWh) of electricity produced. Using these factors, a certain electricity demand (input)[2] for a particular stage of an energy cycle can then be translated into the associated secondary environmental emissions/wastes[3]:

Factor (in lbs/MWh) x MWh consumed = Pounds of pollution (or waste)[4].

Because the mix of generating units and, hence, the environmental effects of electricity production, vary significantly among regions of the United States, average factors for each Federal Region were calculated, so that a variety of different locations could be examined.

For the biomass-ethanol energy cycle, six sites were examined (i.e., Chicago, Illinois as a year 2000 location and as year 2010 locations: Tifton, Georgia; Peoria, Illinois; Lincoln, Nebraska; Portland, Oregon; and Rochester, New York). With the exception of electricity associated with the gasoline inputs to ethanol fuel, for each hypothetical site, the electricity inputs used in all stages of the biomass-ethanol cycle were assumed to be generated in the Federal Regions in which these sites are located (see Figure H-1 for a map of the Federal Regions). In other words, any electricity needed for biomass collection/harvesting,

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[2] It is assumed that no electricity is lost between production and consumption. Although this is inaccurate, the loss is fairly small and this simplification should not significantly alter the results.

[3] In the context of the biomass-ethanol and crude oil-reformulated gasoline energy cycles examined in this study, the emissions associated with the production of electricity are called "secondary" emissions, because unlike the other environmental emissions that are included in this analysis, they do not result directly from the operation of a stage in the energy cycle. (Emissions of operation are termed "primary" emissions). Instead, they result from the production of an input to the energy cycle.

[4]The final calculation to estimate emissions and waste volumes associated with electricity production for each scenario was conducted by multiplying the amount of electricity (expressed in MBTUs) that is consumed in each stage of the energy cycle by the appropriate environmental factor expressed in the units lbs per MBTU. This calculation requires a conversion factor of 3.4119 MBTU per MWh.

transportation, and conversion, as well as ethanol distribution and end use, was assumed to be generated by an "average" electric utility located in the Federal Region. Section H.3 (below) describes the details of the computation of the electricity generation emission/waste factors which are weighted based on the projected generation mix in each region for the years 2000 and 2010. Emissions associated with electricity used in producing gasoline, which constitutes 90% of the ethanol fuel in the year 2000 and 5% of the ethanol fuel in the year 2010, were calculated as described in Section H.4[5].

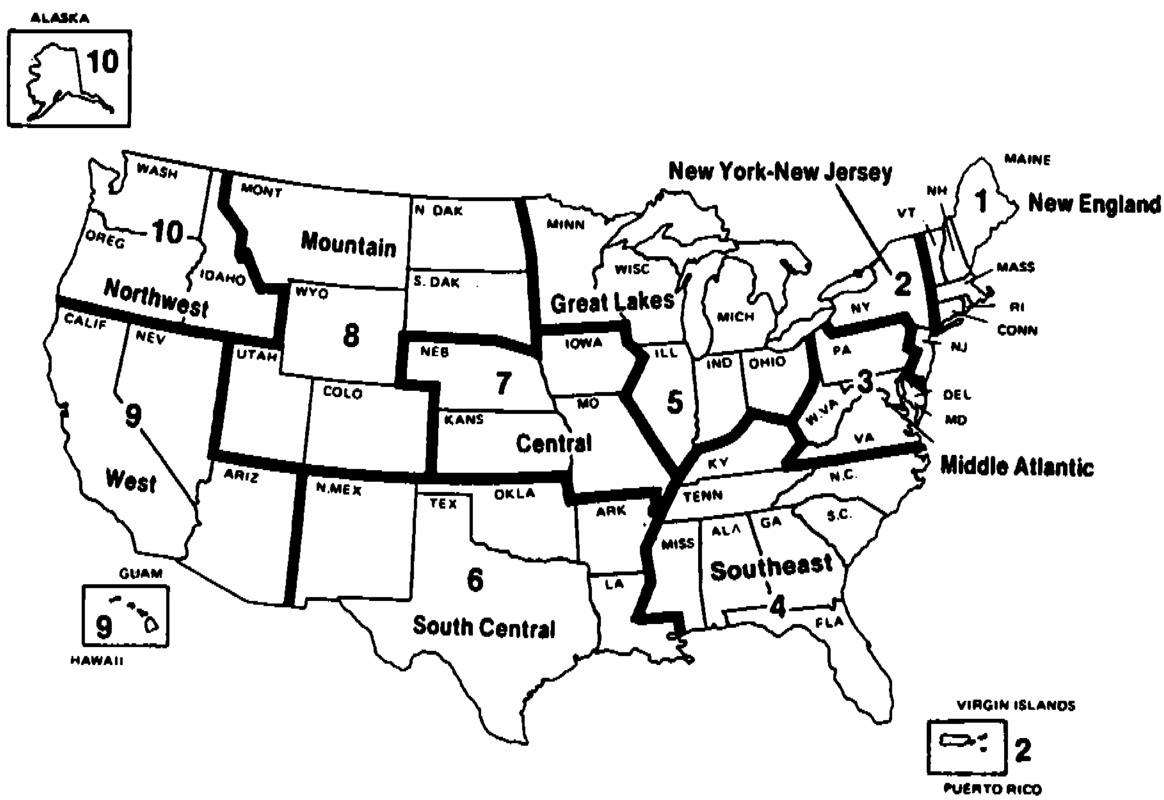

Figure H-1. Map of Federal Regions

[5]It is important to note that because the ethanol blend evaluated in the year 2000 is 90% gasoline, the electricity consumption associated with the crude oil-reformulated gasoline energy cycle has a major effect on year 2000 biomass-ethanol energy cycle. Further, in the overall analysis it was assumed that the gasoline and ethanol components would be mixed somewhere within the fuel distribution system (probably at a marketing terminal), however, what distances each fuel would be transported before and after mixing and how much of the existing infrastructure could be used was not highly scrutinized. Because there is considerable electricity consumption in the distribution stage of both fuels, overall electricity consumption is dramatically affected by the assumptions for fuel distribution. Assumptions used in this segment of the analysis are biased toward improving the outlook of gasoline. The analysis could benefit from additional analytical attention to this area. The fuel distribution projections for the year 2010 are much more balanced.

Unlike ethanol production which will require an infrastructure that is largely concentrated within one region, reformulated gasoline (both as a direct vehicle fuel and as an input to ethanol-blend fuels) will be produced using the existing, geographically distributed infrastructure for oil production, crude transportation, refining, etc. To reflect this, a national average mix of electricity sources was computed for the years 2000 and 2010 for each stage of the energy cycle: crude oil production, crude transportation, refining, and gasoline distribution.[6] To determine the most likely mix of generating units expected to service each stage, the current regional distribution of oil-related activities was characterized. Next the expected regional shifts in some of these activities over time due to potential changes in oil production projected in the National Energy Strategy (e.g., an increase in Alaskan oil) were identified. These regional shares of oil-related activities were used in conjunction with the environmental factors associated with electricity production in each region (the same factors that were used for the biomass-ethanol scenarios) to estimate the average environmental factors for each oil-related energy cycle stage. Further detail on the methodology and data sources are provided in Section H.4 below.

H.3 Estimation of Regional Environmental Factors For Electricity Generation

The following sections describe the computations and sources of information for the regional air pollutant, carbon dioxide and solid waste factors.

H.3.1 Air Pollutant and Carbon Dioxide Emissions

Air pollutant emission factors for electricity generation in the ten Federal Regions for the years 2000 and 2010 were estimated principally from projections made by Energy Information Administration (EIA) and reported in the publication, *Annual Outlook for U.S. Electric Power 1991: Projections Through 2010.*[7] The average regional air emission factors for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2) were calculated by dividing total regional emissions from generation (both utility and non-utility sources) by total regional generation, for each year of interest. The results are shown in Tables H.2 and H.3 for the years 2000 and 2010, respectively. The EIA projections consider the effect of the Clean Air Act Amendments of 1990 on sulfur dioxide emissions.
For total suspended particulates (TSP), information was extracted from *Energy Systems Emissions and Materiel Requirements (Meridian 1989)* and *Energy Technology Characterization Handbook: Energy Pollution and Control Factors (DOE 1983)* for a typical pulverized coal plant,[8] oil-fired steam plant, and gas-fired steam plant. The calculation of average TSP

[6]No electricity was assumed to be consumed in the end-use stage.

[7]Tables B1 through B10 (EIA 1991).

[8]Emission factors for atmospheric fluidized bed and other coal technologies are similar to those for pulverized coal plants. Since the technology of choice in 2000 and 2010 is speculative, the pulverized coal technology, which is the one most commonly used today, seems a reasonable choice for this analysis.

Table H-2.
Air Emissions Factors by Region - 2000

Region[a]	Generation (1000 MWh)	Emissions (1000 tons)			Emissions (lb/MWh)		
		SO_2[b]	NO_x	CO_2	SO_2	NO_x	CO_2
1 New England	140,400	373	100	39,600	5.31	1.43	564.1
2 New York/ New Jersey	226,600	434	200	99,100	3.83	1.77	874.1
3 Middle Atlantic	407,600	2310	600	294,600	11.38	2.94	1445.5
4 Southeast	776,700	2468	1400	516,200	6.36	3.61	1329.2
5 Great Lakes	649,500	2297	1600	516,700	7.07	4.93	1591.1
6 South Central	546,300	682	1000	404,300	2.50	3.66	1480.1
7 Central	183,800	398	600	162,800	4.33	6.53	1770.5
8 Mountain	183,800	321	500	170,000	3.49	5.44	1849.8
9 West	357,700	165	500	164,300	0.92	2.80	918.6
10 Northwest	187,700	52	100	20,600	0.55	1.07	219.5

(a) The regions are the standard Federal Regions (see Figure H.1)
(b) The total SO_2 emissions are emissions from generation. It was assumed that regions purchase emission allowances in order to meet generation needs.

Table H-3.
Air Emission Factors by Region - 2010

Region[a]	Generation (1000 MWh)	Emissions (1000 tons)			Emissions (lb/MWh)		
		SO2[b]	NO^x	CO_2	SO_2	NO_x	CO_2
1 New England	169,400	242	200	64,200	2.86	2.36	758.0
2 New York/ New Jersey	282,100	320	400	156,500	2.27	2.84	1109.5
3 Middle Atlantic	482,500	2016	700	350,600	8.36	2.90	1453.3
4 Southeast	934,400	2327	1700	645,800	4.98	3.64	1382.3
5 Great Lakes	798,000	2419	2000	614,600	6.06	5.01	1540.4
6 South Central	644,800	688	1100	467,000	2.13	3.41	1448.5
7 Central	217,700	543	700	191,800	4.99	6.43	1762.1
8 Mountain	210,500	243	500	185,900	2.31	4.75	1766.3
9 West	459,000	157	600	233,900	0.68	2.61	1019.2
10 Northwest	232,400	28	200	47,000	0.24	1.72	404.5

(a) The regions are the standard Federal Regions (see Figure H.1)
(b) The total SO_2 emissions are projected emissions from generation. Some regions are assumed to purchase emissions allowances in order to meet generation needs.

factors was based on the typical values for the above-referenced generation technologies and the percentage of coal-, gas-, and oil-fired generation projected for the years 2000 and 2010, as reported in the *Annual Outlook for U.S. Electric Power 1991: Projections Through 2010* (EIA 1991). The values for typical generation are shown in Table H.4. The percentage of generation by fuel source on a regional basis for the years 2000 and 2010 is shown in Tables H.5 and H.6, respectively. The weighted average values for total suspended particulates are provided in Table H.7.

H.3.2 Solid Wastes

Solid wastes are produced from generation associated with both coal- and oil-fired power plants.[9] Based on information provided in *Energy Technology Characterizations Handbook: Energy Pollution and Control Factors (DOE 1983)*, the solid waste produced by coal-fired power plants is approximately 467.4 pounds per MWh. For oil-fired plants the value is 112.0 pounds per MWh. Wastes included are ash (bottom and fly ash), sulfur removal sludge/waste, and coal-cleaning wastes (coal cleaning is assumed to occur at the plant).[10] Based on the values from DOE (1983) and the weighted generation by fuel mix for each region shown in Tables H.5 and H.6, the regionally-weighted solid waste production values shown in Table H.8 were calculated.

Table H-4.
Emissions Factors for Total Suspended Particulates by Generation Technology

Coal Fired Power Plant:	0.285 Pounds per Megawatt-hour
Oil Fired Power Plant:	2.799 Pounds per Megawatt-hour
Gas Fired Power Plant:	0.293 Pounds per Megawatt-hour

Sources: Meridian 1989; DOE 1983.

[9]Next-order effects, i.e., the wastes associated with power plant fuel extraction, processing, and transportation were not included.

[10]Values are based on a plant using eastern coal, an electrostatic precipitator for particulate control, and flue-gas desulfurization (FGD) for SO_2 control. Use of this value may overstate the waste volume, since not all plants in 2000 and 2010 will use FGD devices.

Table H-5.
Regional Fuel Mix (Percent of Total) - 2000

Region	Coal	Gas	Oil	Other[a]
1 New England	12.3	6.8	24.0	56.0
2 New York/ New Jersey	13.5	18.7	23.0	44.7
3 Middle Atlantic	63.3	6.3	7.6	22.9
4 Southeast	55.3	7.9	6.6	30.2
5 Great Lakes	68.5	8.0	0.7	22.8
6 South Central	45.0	41.0	0.0	13.9
7 Central	69.4	15.8	0.4	14.4
8 Mountain	78.6	3.8	1.2	16.5
9 West	19.3	28.7	5.0	47.0
10 Northwest	4.1	5.9	1.6	88.5

(a) Other generation includes nuclear, renewables, and purchases from suppliers outside the region.

Source: EIA 1991.

Table H-6.
Regional Fuel Mix (Percent of Total) - 2010

Region	Coal	Gas	Oil	Other[a]
1 New England	15.5	9.7	20.3	54.6
2 New York/ New Jersey	30.1	18.5	15.7	25.7
3 Middle Atlantic	65.8	8.7	4.2	21.3
4 Southeast	60.8	6.8	4.5	28.0
5 Great Lakes	65.8	14.5	0.4	19.3
6 South Central	45.1	41.8	0.0	13.1
7 Central	73.6	12.4	0.7	13.3
8 Mountain	73.5	8.8	1.0	16.7
9 West	32.6	21.1	3.3	43.0
10 Northwest	14.6	5.4	0.9	79.1

(a) Other generation includes nuclear, renewables, and purchases from suppliers outside the region. These electricity sources are assumed to contribute on emission.

Source: EIA 1991.

Table H-7.
Weighted Emission Factors for Total Suspended Particulates by Region
(pounds per MWh)

Region	2000	2010
1 New England	0.73	0.64
2 New York/ New Jersey	0.74	0.58
3 Middle Atlantic	0.41	0.33
4 Southeast	0.37	0.32
5 Great Lakes	0.24	0.24
6 South Central	0.25	0.25
7 Central	0.25	0.27
8 Mountain	0.27	0.26
9 West	0.28	0.25
10 Northwest	0.07	0.08

Table H.8.
Weighted Factors for Solid Waste Generation by Region
(pounds per MWh)

Region	2000	2010
1 New England	84.4	95.2
2 New York/ New Jersey	88.8	158.3
3 Middle Atlantic	304.4	312.3
4 Southeast	265.9	289.2
5 Great Lakes	321.0	308.0
6 South Central	210.3	210.8
7 Central	324.8	344.8
8 Mountain	368.7	344.7
9 West	95.8	156.1
10 Northwest	20.9	69.3

H.4 Calculation of Regional Shares of Electricity for Use in the Crude Oil-Reformulated Gasoline Energy Cycle

Only two reformulated gasoline scenarios are examined in the analysis (i.e., one for the year 2000 and one for the year 2010), as opposed to a series of regional sensitivity scenarios, such as those evaluated for the biomass-ethanol energy cycle. Because the crude oil-reformulated gasoline energy cycle is disbursed across multiple geographic regions, the electricity-related environmental factors had to be regionally weight-averaged. Currently, oil production is regionally concentrated, with high levels of activity in the Texas-Louisiana-Oklahoma area (Region 6), the north central U.S. including Wyoming (Region 8), California (Region 9), and Washington State and Alaska (Region 10). Refining activity is concentrated in the Texas-Louisiana area (Region 6), and California (Region 9) with minor concentrations in New Jersey, Pennsylvania, Illinois and Ohio, and Washington (Regions 2, 3, 5, and 10, respectively). On the other hand, the distribution of gasoline from the refinery to the end users is a dispersed activity, occurring in all states. To capture the environmental emissions/wastes of the electricity consumed in the production, refining, and distribution stages of the reformulated gasoline energy cycle, the differences in the regional distributions of the these activities was considered, and regional environmental factors (documented above in section H.3) were weight-averaged separately for each stage of the crude oil-reformulated gasoline energy cycle.

H.4.1 Crude Oil Production and Transportation

Table H.9 shows current levels of crude oil production, by state and region.[11] These data provide the principal basis for the regional shares of both crude oil production and crude oil transportation. However, the shares were altered for 2000 and 2010 to reflect some broad changes expected in regional crude oil production. The National Energy Strategy (NES) projections for regional production of crude oil are shown in Table H.10. For this analysis, the regional shares to were matched to the NES projected oil production onshore,[12] offshore, and in Alaska (including the North Slope and ANWR). In each of these three categories for each of the two projection years (2000 and 2010), the data shown in Table H.9 was used to provide the regional breakdown within the category. The onshore production was distributed to Regions 3, 4, 5, 6, 7, 8 and 9 in proportion to each region's current share of onshore production. Similarly, the offshore production was distributed to Regions 6 and 9, and the Alaskan production was assigned to Region 10. The resulting regional shares for both years are shown in Table H.11.

These shares were assumed to be a surrogate for the distribution of electricity consumption by crude oil production and transportation activity. They were used to weight-average the regional environmental factors (see Section H.3), resulting in a set of nationally-averaged factors for electricity consumed in the crude oil production and transportation stages of the crude oil-reformulated gasoline energy cycle.

H.4.2 Refining

Regional shares of oil refining activity were assumed to remain constant over time. The shares were based on refining capacity in 1990, as shown in Table H.12. These shares were assumed to reflect the distribution of electricity use in the refining industry, which was assumed to be located in the same sites in 2000 and 2010 as it was in 1990. The shares were used to weight-average the environmental factors (see Section H.3) to compute nationally-averaged factors for electricity consumption in the refining stage of the crude oil-reformulated gasoline cycle.

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[11]Based on Table 4 of *U.S. Oil and Gas Reserves (EIA 1990)*. Values are for 1988.

[12]Natural gas liquids and enhanced oil recovery were grouped with conventional onshore production in the 48 lower states to get the total onshore production target.

Table H-9.
Crude Oil Production by Region[a]

Region/State	Crude Oil Production	
3 Middle Atlantic		
Pennsylvania	2	
West Virginia	3	
Total		5
4 Southeast		
Alabama	21	
Florida	9	
Kentucky	5	
Mississippi	29	
Total		64
5 Midwest		
Illinois	23	
Indiana	4	
Michigan	23	
Ohio	10	
Total		60
6 South Central		
Arkansas	13	
Louisiana Onshore	142	
Louisiana Offshore	290	
New Mexico	74	
Oklahoma	136	
Texas Onshore	732	
Texas Offshore	29	
Total Onshore		1097
Total Offshore		319

Table H-9 (cntd).
Crude Oil Production by Region

Region/State	Crude Oil Production	
7 Central		
Kansas	55	
Nebraska	6	
Total		61
8 North Central		
Colorado	32	
Montana	23	
North Dakota	39	
Utah	33	
Wyoming	112	
Total		239
9 West		
California Onshore	328	
California Offshore	58	
Total Onshore		328
Total Offshore		58
10 Northwest		
Alaska	734	
Total		734

(a) No significant production occurs in Regions 1 and 2.

Source: EIA 1990.

Table H-10.
NES Scenario Case - U.S. Sources and Technologies of Petroleum Energy in 2000 and 2010 (MMBD)

Petroleum Source and Recovery Technologies	2000	2010
Lower 48		
Conventional[a]		
- Onshore	4.0	3.6
- Offshore	1.0	0.9
Natural Gas Liquids[b]	1.9	1.6
Enhanced Oil Recovery		
- Thermal	0.7	1.3
- Advanced and Other	0.7	1.4
Subtotal Lower 48	8.3	8.8
Alaska North Slope		
Conventional	0.9	0.7
Advanced Technology Oil Recovery[c]	0.0	0.5[e]
Arctic National Wildlife Refuge (ANWR)[d]	0.0	0.5
Subtotal Alaska North Slope and ANWR	0.9	1.7
Outer Continental Shelf (OCS)[e]	0.0	0.1
Total Petroleum Energy - MMBD	9.3	10.6
- Quads	18.3	21.4

(a) Conventional crude oil includes approximately 20 percent offshore oil and 10 percent stripper well oil in 2000 and 2010.
(b) Assumes that the natural gas liquids estimates of Table C-10 (see Source, below) are for Lower 48.
(c) Includes oil enhanced recovery.
(d) According to pp. 38 and 401 of Source (below), the resource peaks at 870,000 barrels/day in 2005.
(e) U.S. Department of Energy, *The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for the National Energy Strategy*, Report No. SR/NES/90-05, Washington, D.C., Tables A1 and A2, pp.28-30, December 1990.
(f) According to p. 39, resource enters production phase in 2010.

Source: Except as noted above, DOE 1991, Table C-10, p. 122.

Table H-11.
Future Crude Oil Production and Distribution by Region[a]

Region	Percent Contribution	
	2000	2010
3 Middle Atlantic	0.2	0.2
4 Southeast	2.8	2.6
5 Great Lakes	2.6	2.4
6 South Central	56.1	51.7
7 Central	2.1	2.5
8 Mountain	10.2	9.7
9 West	15.7	14.6
10 Northwest	9.8	16.2

(a) No significant production occurs in Regions 1 and 2.

Table H-12.
Major U.S. Refining Capacity by Region - 1990[a]

Region/State	Refining Capacity	
	MMBD	Percent Contribution
2 New York/ New Jersey		
New Jersey	0.5	
Total	0.5	4
3 Middle Atlantic		
Pennsylvania	0.7	
Delaware	0.1	
Total	0.8	6
5 Great Lakes		
Illinois	1.0	
Indiana	0.4	
Ohio	0.5	
Total	1.9	14
6 South Central		
Oklahoma	0.4	
Texas	3.9	
Louisiana	2.3	
Total	6.6	50
7 Central		
Kansas	0.4	
Total	0.4	3
9 West		
California	2.2	
Total	2.2	17
10 Northwest		
Washington	0.5	
Total	0.5	4

(a) No significant production occurs in Regions 1 and 2.

Source: Thrash 1991.

Table H-13.
Gasoline Consumption by Region - 1989

Region	Gasoline Consumption (Trillion BTU)	Percent of Total
1 New England	695.5	5.0
2 New York/ New Jersey	1128.2	8.0
3 Middle Atlantic	1369.4	9.7
4 Southeast	2773.3	19.7
5 Great Lakes	2585.0	18.4
6 South Central	1772.6	12.6
7 Central	759.0	5.4
8 Mountain	462.7	3.3
9 West	1922.4	13.7
10 Northwest	581.9	4.1
Total[a]	14050.0	100.0

(a) Values may not sum to total due to independent rounding.

Source: EIA 1991.

H.4.3 Gasoline Distribution

Regional shares in 2000 and 2010 for the electricity consumed in the distribution of gasoline from the refinery to the end users were based on the current regional consumption of gasoline[13] (see Table H.13). In a manner identical to the method for the refining stage, shares were used to weight-average the electricity-related

[13]Data on gasoline consumption were readily available, whereas more accurate surrogates, such as miles of pipeline, by region, and gasoline volumes transported by rail in each region, were not easily accessible at the time of the analysis. This is an area that could be improved in future analyses.

environmental factors to obtain a national average for the gasoline distribution stage of the crude oil-reformulated gasoline cycle.

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APPENDIX I

ENERGY BALANCES

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INTRODUCTION

Measures of energy efficiency illustrate the relative difference between the amount of energy used to produce a fuel and the energy contained in the fuel itself. When two or more alternative forms of energy provide the same services--miles or kwhr--then the fuel which uses the fewest energy resources is socially desirable, abstracting from other issues.

There are many different ways to calculate energy efficiency. Some of the methods used in the past have been distinguished by the types of energy inputs included, allocation methods used to apportion energy inputs between co-products, and standards of measure. The following discussion briefly describes each of these issues.

At least four different types of energy inputs have been defined in previous studies: direct, indirect, fossil, non-fossil. Direct energy inputs includes fuels such as diesel, gasoline, coal, natural gas, and electricity that are directly consumed during the production of the fuel. For example, coal is consumed in a power plant to produce electricity. Indirect energy inputs are sometimes called embedded, and these are the amounts of energy inputs that are consumed in the manufacture of another input. For example, natural gas and coal are consumed during the production of nitrogen fertilizer, which is an input to corn-ethanol production. The concept of a total energy cycle attempts to include both the embedded energy associated with the life cycle of products (including energy products) that become inputs to a fuel cycle and the direct energy inputs of a fuel cycle.

Sometimes a distinction is made between fossil fuel inputs and non-fossil fuel inputs. Past NREL publications did not consistently included the waste lignin consumed as a boiler fuel in their energy analyses of biomass ethanol because it is renewable (or because it is a waste). The concept behind energy efficiency is to conserve the use of depletable resources. Because fossil fuels are depletable they are always included in energy analyses. Renewable energy resources have traditionally been viewed as inexhaustible, and not necessarily relevant to energy efficiency estimates. This belief has been tempered over the years as researchers and developers have discovered that the "renewable" energy resource may replenish itself (like biomass) or may be inexhaustible in theory (like sunlight) but the number and quality of the sites that are available to capture the resource provide a limit to the amount of resource ultimately available.

Allocation measures attempt to distinguish between the energy consumed to produce one of two or more products. For example, an integrated refinery commonly produces a number of products which could include gasoline, ethers, diesel, propane, #2 and #6 oils, coke, asphalt, and numerous gaseous and liquid chemicals. The crude oil feedstock and the purchased natural gas and electricity are allocated between each of the products produced according to the process efficiencies of making each product. In corn-ethanol analyses, the issue has been how to handle DDG (distiller's dried grains) and ethanol. The debate centers around whether DDG (and CO_2) is a by-product, co-product or waste, and should any of the energy inputs should be allocated to DDG (and CO_2) and if so, in what proportion--by value, by weight, by energy content?

The standard of measure is another area where energy analyses differ substantially. The analysis could compare the energy input per gallon of fuel produced, per Btu of fuel produced, per mile traveled in two comparable vehicles, or per mile traveled in optimized vehicles. The difference between the energy content of ethanol and gasoline cause differences in the reported energy balances depending on the standard of measure used. To confuse matters more, analysts can use estimates of the lower or the higher heating value for each energy input or use the mid-point heating value for estimating the Btus of energy inputs and energy outputs. Some analysts estimate kwhr of electricity using a Btu energy equivalent and other account for the process efficiencies of producing electricity and use a heat rate.

This study will attempt to be a clear as possible about the assumptions made. Readers are free to recalculate the energy balances using any assumptions they feel more comfortable with.

METHODOLOGY

This study uses three methods to address the issues of energy efficiency: process energy balance, fossil fuel energy balance, and the total energy balance. Each measure provides a different way of examining the energy efficiency issue. The numerator of each energy ratio is equal to the sum of the energy inputs (Btus) required to produce enough Btus of fuel to supply a fleet of optimized light-duty passenger cars driven 1 billion miles per year. The energy output is the number of Btus of fuel required to produce 1 billion miles of transportation in said vehicles. Because the billion miles divide out of both the numerator and the denominator of the ratio, the ratio can be interpreted as the number of Btus of inputs required to produce 1 Btu of output.

$$\frac{\text{Btus of energy inputs/Billion VMT}}{\text{Btus of fuel/Billion VMT}} = \qquad \text{Btu input/Btu output}$$

Thus, the energy content of the fuel and the efficiency of the vehicles using the fuels are reflected in the estimates of energy efficiency used in this study. The difference between the ratios calculated centers on which inputs are included in the analysis. These differences will be described in more detail shortly. The assumptions and background necessary to understand or calculate the energy ratios are described next.

Assumptions

There are 8 basecases examined in this report. The basecases are distinguished by type of fuel, feedstock, year of the analysis, and location of fuel use; they are summarized below.

E10: A specially designed base gasoline with 10 percent ethanol added. The ethanol is produced from the organic fraction of municipal solid waste (MSW). The fuel is produced and used in the Chicago/Peoria area of Illinois in the year 2000. The fuel is consumed in conventional engines that reflect some fuel economy advances by 2000.

RG2000: A reformulated gasoline made with 15 % MTBE oxygenates used nationwide in the year 2000. The fuel is consumed in conventional engines that reflect some fuel economy advances by 2000.

E95: There are five cases where pure ethanol is denatured with 5 percent gasoline. These cases are referred to as E95 cases. The ethanol portion of E95 is produced from lignocellulosic crops--energy crops such as trees, grasses, etc. The fuel is consumed in optimized vehicles in the year 2010. The E95 is produced and consumed in and around five locations: Tifton, GA; Lincoln, NE; Rochester, NY; Portland, OR; and Peoria, IL.

RG2010: A reformulated gasoline made with 15 % MTBE oxygenates used nationwide in the year 2010. The fuel is consumed in conventional engines that reflect some fuel economy advances by 2010.

The assumptions on fuel efficiency are described in Table 3 in Appendix E, Ethanol and Reformulated End Use. Table I-1 provides the estimates of the number of gallons of each fuel required per billion VMT.

Table I-1. Fuel Requirements for Each Basecase

	Million Gallons per billion VMT	10^{12} Btu per billion VMT
E10	33.1	3.54
RG2000	32.5	3.59
E95	35.4	2.75
RG2010	28.1	3.10

Table I-2 shows the energy content assumptions used for direct and indirect energy inputs, and energy outputs. In all cases except for biomass feedstocks, the lower heating value of the fuels are used. For biomass feedstocks, the higher energy value is assumed because there is no limit on the lower heating value of biomass.

A product life cycle analysis for fertilizer and a total energy cycle for electricity would be necessary for a comprehensive study of energy balances in this report. Such studies were not available at the time. In this analysis, only the energy consumed during the manufacture of fertilizers and electricity generation are included in the estimates of embedded energy. A heat rate of 10,400 Btu/kWh is assumed for electricity consumed in the fuel cycles. This value allows

Table I-2. Energy Value Assumptions

Input	Units	Btu/Unit
Feedstocks		
Crude oil	Gallons	138,000
Biomass	Dry tons	1.50E7
Material and Energy Inputs		
Electricity	Kwhr	10,400
Natural gas	MMCF*	1.00E9
Diesel #2	Gallons	128,700
Diesel #6	Gallons	137,500
Gasoline	Gallons	117,700
K20 fertilizer	Tons	6.00E6
P2O5 fertilizer	Tons	6.00E6
Phosphate	Tons	6.00E6
N-Fertilizer	Tons	5.00E7
Urea	Tons	3.08E7
Ammonia	Tons	4.12E7
MTBE	Gallons	94,072
Outputs		
E95	Gallons	77,730
E10	Gallons	107,140
Reform. Gasoline	Gallons	110,600

*Million cubic feet

us to capture the efficiency losses associated with producing electricity. This estimate does not include the energy required to mine coal, transport fuel oil or other intrinsic aspects of a full fuel cycle.

There were a range of possible values available in the literature for the energy consumption in fertilizer manufacturing. After a review of existing literature, Deluchi (1991) chose the following values: 25,000 Btu/lb of nitrogen contained in ammonia; 3,000 Btu/lb for P_2O_5, K_2O, and phosphate fertilizer; and 28,860 Btu/lb of nitrogen contained in ammonium nitrate. The energy estimates for nitrogen fertilizers were adjusted by the percent of nitrogen by weight in each type of fertilizer: 82 percent for anhydrous ammonia, and 33 percent for ammonium nitrate. Because these estimates were felt to be the best available estimates, these values were used in this study. Urea was estimated to require 33,000 Btu/lb of nitrogen (45 percent nitrogen by weight) (Riley, 1991).

The inputs for each of the basecases are provided in Tables I-3 through I-10. These estimates are the result of allocating inputs between coproducts and by-products. Tables I-3 through I-10 reflect only those inputs that are attributed to the fuel produced. The fraction of the inputs required to produce coproducts have been eliminated. Sensitivity cases have been produced (but not shown here) that examine the impacts of various allocation assumptions. Tables I-3 through I-10 show only the inputs required to produce enough fuel to travel 1 billion miles.

In the reformulated gasoline basecases, crude oil production, transportation, and refining inputs have been allocated between reformulated gasoline and all other coproducts. The inputs reported in Table I-3 and I-5 show only those inputs that are consumed to produce reformulated gasoline. The inputs consumed to produce other petroleum products have been eliminated. There were two specific allocation steps. First, associated natural gas is sometimes coproduced with crude oil at the wellhead. The inputs shown in the crude oil production stage have been allocated between natural gas and crude oil based on the Btu value of each fuel. Thus, only 58 percent of the inputs associated with crude oil production are assigned to the crude oil itself.

The second allocation step occurs in the refining stage and is carried back through the crude oil production and transportation stages. In the year 2000, only 35 percent of a barrel of oil is ultimately transformed into gasoline. The remainder of the barrel is transformed into other petroleum products. The ratio of 35 percent was calculated as the ratio of reformulated gasoline energy (Btu) to the total Btu output of a refinery (Table F-75 in Appendix F, Benchmark Reformulated Gasoline Fuel Cycle). Based on this assumption, all of the inputs to the refining process were divided between gasoline and all other products using the same ratio (Figure I-1). Thus, Table I-3 show only 35 percent of the refinery inputs in the fuel production stage because the remainder are associated with other petroleum products, not reformulated gasoline.

Because only 35 percent of the barrel of oil produced and transported is transformed into gasoline, only 35 percent of the transportation and crude oil production inputs are assigned to the reformulated gasoline basecase. Since only 58 percent of the inputs to crude oil production were attributed to crude oil (the remainder were assigned to associated natural gas), further reducing this estimate by 35 percent results in only 20.3 percent of the inputs associated with crude oil production being assigned to reformulated gasoline fuel cycles (shown in Table I-3).

In the year 2010 this same process of allocation is repeated; however, only 30 percent of a barrel of crude oil is transformed into reformulated gasoline because of the changing nature of the crude oil characteristics and the changes in demand for gasoline versus other petroleum products, such as diesel. Thus, only 30 percent of the total inputs associated with crude oil refining and transportation are shown in Table I-5, and only 17.4 percent of the crude oil production inputs are shown (30 percent of 58 percent of crude oil production inputs).

These same allocations were assumed to exist for foreign oil imports for the years 2000 and 2010. Foreign oil was assigned the same estimates of production inputs per barrel as U.S. crude oil. Because this proxy may under or over estimate the actual requirements, future research in this area is recommended.

Table I-3. Fuel Cycle Inventory: Reformulated Gasoline, 2000

Emission or Concern	Units	End-Use	Gas Dist.	Crude Refining	Crude Trans	Crude Prod.	Grand Total
Inputs							
Crude oil	bbls	0	0	0	0	0	0
Diesel	gallons	0	50000	0	6000	0	56000
Diesel (No. 6)	gallons	0	56000	0	378000	0	434000
Ethanol-10	gallons	0	0	0	0	0	0
Ethanol-95	gallons	0	0	0	0	0	0
Gasoline	gallons	0	0	0	0	0	0
Insecticides	tons	0	0	0	0	0	0
MTBE	gallons	0	0	3.61E+06	0	0	3.61E+06
Natural gas	mmscf	0	0	160	0	0	160
Refinery Products	gallons	0	0	0	0	0	0
Water	gallons	0	0	0	0	141000	141000
Electricity	kWh	0	2.04E+07	4.52E+06	7.08E+06	3.71E+06	3.57E+07
Herbicides	tons	0	0	0	0	0	0
K2O-Fertilizer	tons	0	0	0	0	0	0
N-Fertilizer	tons	0	0	0	0	0	0
P2O5-Fertilizer	tons	0	0	0	0	0	0
Antifoam	tons	0	0	0	0	0	0
CS Liquor	tons	0	0	0	0	0	0
Glucose	tons	0	0	0	0	0	0
H2SO4	tons	0	0	0	0	0	0
Lime	tons	0	0	0	0	0	0
Limestone	tons	0	0	0	0	0	0
NH3	tons	0	0	0	0	0	0
Nutrients	tons	0	0	0	0	0	0
BFW Chemicals							
Amine	tons	0	0	0	0	0	0
Hydrazine	tons	0	0	0	0	0	0
Na2PO4	tons	0	0	0	0	0	0
CW Chemicals							0
Orthophosphate	tons	0	0	0	0	0	0
Phosphonate	tons	0	0	0	0	0	0
Polyphosphate	tons	0	0	0	0	0	0
Silicate	tons	0	0	0	0	0	0
Zinc	tons	0	0	0	0	0	0
WWT Chemicals							
Phosphate	tons	0	0	0	0	0	0
Polymer	tons	0	0	0	0	0	0
Urea	tons	0	0	0	0	0	0

Note: These numbers are subject to change as revisions or refinements proceed. These numbers are derived from calcuations shown in the appendices and modified as described in the author's notes and the main body of the report. These values do not necessarily reflect the degree of signficance implied by the number of digits. These numbers are reported as derived in order to enable the interested person to recalculate and thus verify calculations made.

Table I-4. Fuel Cycle Inventory: E10

Emission or Concern	Units	End-Use	E-10/ E-95 Dist.	E-95 Prodtn.	MSW Trans	MSW Sort	MSW Collctn	Grand Total
Inputs								
Crude oil	bbls	0	0	0	0	0	0	0
Diesel	gallons	0	89000	4350	16530	6090	18270	134240
Diesel (No. 6)	gallons	0	397000	2000	0	0	0	399000
Ethanol-10	gallons	0	0	0	0	0	0	0
Ethanol-95	gallons	0	0	0	0	0	0	0
Gasoline	gallons	0	29632000	152250	0	0	0	29784250
Insecticides	tons	0	0	0	0	0	0	0
MTBE	gallons	0	3302000	20000	0	0	0	3322000
Natural gas	mmscf	0	139	0.9	0	0	0	139.9
Refinery Products	gallons	0	0	0	0	0	0	0
Water	gallons	0	140000	30828450	0	0	0	30968450
Electricity	kWh	0	42174000	-3299000	214890	1295430	0	40385320
Herbicides	tons	0	0	0	0	0	0	0
K2O-Fertilizer	tons	0	0	0	0	0	0	0
N-Fertilizer	tons	0	0	0	0	0	0	0
P2O5-Fertilizer	tons	0	0	0	0	0	0	0
Antifoam	tons	0	0	3.48	0	0	0	3.48
CS Liquor	tons	0	0	57.42	0	0	0	57.42
Glucose	tons	0	0	69.6	0	0	0	69.6
H2SO4	tons	0	0	522	0	0	0	522
Lime	tons	0	0	382.8	0	0	0	382.8
Limestone	tons	0	0	78.3	0	0	0	78.3
NH3	tons	0	0	88.4	0	0	0	88.4
Nutrients	tons	0	0	16.53	0	0	0	16.53
BFW Chemicals								
Amine	tons	0	0	0.0609	0	0	0	0.0609
Hydrazine	tons	0	0	0.174	0	0	0	0.174
Na2PO4	tons	0	0	0.0174	0	0	0	0.0174
CW Chemicals								
Orthophosphate	tons	0	0	0.2001	0	0	0	0.2001
Phosphonate	tons	0	0	0.0609	0	0	0	0.0609
Polyphosphate	tons	0	0	0.2001	0	0	0	0.2001
Silicate	tons	0	0	0.1653	0	0	0	0.1653
Zinc	tons	0	0	0.087	0	0	0	0.087
WWT Chemicals								
Phosphate	tons	0	0	8.7	0	0	0	8.7
Polymer	tons	0	0	0	0	0	0	0
Urea	tons	0	0	0	0	0	0	0

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Table I-5. Fuel Cycle Inventory: Reformulated Gasoline, 2010

Emission or Concern	Units	End-Use	Gas Dist.	Crude Refining	Crude Trans	Crude Prod.	Grand Total
Inputs							
Crude oil	bbls	0	0	0	0	0	0
Diesel	gallons	0	41000	0	6000	0	47000
Diesel (No. 6)	gallons	0	48000	0	354000	0	402000
Ethanol-10	gallons	0	0	0	0	0	0
Ethanol-95	gallons	0	0	0	0	0	0
Gasoline	gallons	0	0	0	0	0	0
Insecticides	tons	0	0	0	0	0	0
MTBE	gallons	0	0	3.12E+06	0	0	3.12E+06
Natural gas	mmscf	0	0	150	0	0	150
Refinery Products	gallons	0	0	0	0	0	0
Water	gallons	0	0	0	0	213000	213000
Electricity	kWh	0	1.76E+07	3.91E+06	6.93E+06	3.35E+06	3.18E+07
Herbicides	tons	0	0	0	0	0	0
K2O-Fertilizer	tons	0	0	0	0	0	0
N-Fertilizer	tons	0	0	0	0	0	0
P2O5-Fertilizer	tons	0	0	0	0	0	0
Antifoam	tons	0	0	0	0	0	0
CS Liquor	tons	0	0	0	0	0	0
Glucose	tons	0	0	0	0	0	0
H2SO4	tons	0	0	0	0	0	0
Lime	tons	0	0	0	0	0	0
Limestone	tons	0	0	0	0	0	0
NH3	tons	0	0	0	0	0	0
Nutrients	tons	0	0	0	0	0	0
BFW Chemicals							
Amine	tons	0	0	0	0	0	0
Hydrazine	tons	0	0	0	0	0	0
Na2PO4	tons	0	0	0	0	0	0
CW Chemicals							0
Orthophosphate	tons	0	0	0	0	0	0
Phosphonate	tons	0	0	0	0	0	0
Polyphosphate	tons	0	0	0	0	0	0
Silicate	tons	0	0	0	0	0	0
Zinc	tons	0	0	0	0	0	0
WWT Chemicals							
Phosphate	tons	0	0	0	0	0	0
Polymer	tons	0	0	0	0	0	0
Urea	tons	0	0	0	0	0	0
[illegible]							

Note: These numbers are subject to change as revisions or refinements proceed. These numbers are derived from calcuations shown in the appendices and modified as described in the author's notes and the main body of the report. These values do not necessarily reflect the degree of signficance implied by the number of digits. These numbers are reported as derived in order to enable the interested person to recalculate and thus verify calculations made.

Table I-6. Fuel Cycle Inventory: E95, Tifton, GA

Emission or Concern	Units	End-Use	E-95 Dist.	E-95 Prodtn.	Fdstk S&T	Aggregate Fdstk	Grass Fdstk	Tree Fdstk	Cane Fdstk	Grand Total
Inputs										
Crude oil	bbls	0	0	0	0	0	0	0	0	0
Diesel	gallons	0	99000	67157	253150	498000	244020	224100	30710	917307
Diesel (No. 6)	gallons	0	0	23000	0	0	0	0	0	23000
Ethanol-10	gallons	0	0	0	0	0	0	0	0	0
Ethanol-95	gallons	0	0	0	0	0	0	0	0	0
Gasoline	gallons	0	0	1473250	0	0	0	0	0	1473250
Insecticides	tons	0	0	0	0	0.415	0.249	0.083	0.083	0.415
MTBE	gallons	0	0	202000	0	0	0	0	0	202000
Natural gas	mmscf	0	0	9.6	0	0	0	0	0	9.6
Refinery Products	gallons	0	0	0	0	0	0	0	0	0
Water	gallons	0	0	226175000	0	0	0	0	0	226175000
Electricity	kWh	0	13311000	-49346000	0	0	0	0	0	-36035000
Herbicides	tons	0	0	0	0	3.569	1.328	1.992	0.166	3.569
K2O-Fertilizer	tons	0	0	0	0	1070.7	838.3	124.5	107.9	1070.7
N-Fertilizer	tons	0	0	0	0	1361.2	755.3	415	182.6	1361.2
P2O5-Fertilizer	tons	0	0	0	0	747	556.1	124.5	66.4	747
Antifoam	tons	0	0	15.77	0	0	0	0	0	15.77
CS Liquor	tons	0	0	265.6	0	0	0	0	0	265.6
Glucose	tons	0	0	506.3	0	0	0	0	0	506.3
H2SO4	tons	0	0	4233	0	0	0	0	0	4233
Lime	tons	0	0	3145.7	0	0	0	0	0	3145.7
Limestone	tons	0	0	514.6	0	0	0	0	0	514.6
NH3	tons	0	0	628.4	0	0	0	0	0	628.4
Nutrients	tons	0	0	76.36	0	0	0	0	0	76.36
BFW Chemicals										
Amine	tons	0	0	0.6225	0	0	0	0	0	0.6225
Hydrazine	tons	0	0	2.075	0	0	0	0	0	2.075
Na2PO4	tons	0	0	0.2075	0	0	0	0	0	0.2075
CW Chemicals										
Orthophosphate	tons	0	0	1.5189	0	0	0	0	0	1.5189
Phosphonate	tons	0	0	0.4565	0	0	0	0	0	0.4565
Polyphosphate	tons	0	0	1.5189	0	0	0	0	0	1.5189
Silicate	tons	0	0	1.2118	0	0	0	0	0	1.2118
Zinc	tons	0	0	0.747	0	0	0	0	0	0.747
WWT Chemicals										
Phosphate	tons	0	0	182.6	0	0	0	0	0	182.6
Polymer	tons	0	0	0	0	0	0	0	0	0
Urea	tons	0	0	415	0	0	0	0	0	415

Note: These numbers are subject to change as revisions or refinements proceed. These numbers are derived from calcuations shown in the appendices and modified as described in the author's notes and the main body of the report. These values do not necessarily reflect the degree of signficance implied by the number of digits. These numbers are reported as derived in order to enable the interested person to recalculate and thus verify calculations made.

Table I-7. Fuel Cycle Inventory: E95, Peoria, IL

Emission or Concern	Units	End-Use	E-95 Dist.	E-95 Prodtn.	Fdstk S&T	Aggregate Fdstk	Grass Fdstk	Tree Fdstk	Cane Fdstk	Grand Total
Inputs										
Crude oil	bbls	0	0	0	0	0	0	0	0	0
Diesel	gallons	0	104000	77073	162360	552680	294380	191880	66420	896113
Diesel (No. 6)	gallons	0	0	23000	0	0	0	0	0	23000
Ethanol-10	gallons	0	0	0	0	0	0	0	0	0
Ethanol-95	gallons	0	0	0	0	0	0	0	0	0
Gasoline	gallons	0	0	1485020	0	0	0	0	0	1485020
Insecticides	tons	0	0	0	0	1.148	0.246	0.082	0.738	1.148
MTBE	gallons	0	0	202000	0	0	0	0	0	202000
Natural gas	mmscf	0	0	9.6	0	0	0	0	0	9.6
Refinery Products	gallons	0	0	0	0	0	0	0	0	0
Water	gallons	0	0	237230100	0	0	0	0	0	237230100
Electricity	kWh	0	13284000	-54849000	0	0	0	0	0	-41565000
Herbicides	tons	0	0	0	0	5.494	1.23	1.23	2.952	5.494
K2O-Fertilizer	tons	0	0	0	0	1123.4	877.4	73.8	172.2	1123.4
N-Fertilizer	tons	0	0	0	0	1402.2	902	254.2	246	1402.2
P2O5-Fertilizer	tons	0	0	0	0	795.4	590.4	73.8	131.2	795.4
Antifoam	tons	0	0	18.04	0	0	0	0	0	18.04
CS Liquor	tons	0	0	282.9	0	0	0	0	0	282.9
Glucose	tons	0	0	533	0	0	0	0	0	533
H2SO4	tons	0	0	4346	0	0	0	0	0	4346
Lime	tons	0	0	3214.4	0	0	0	0	0	3214.4
Limestone	tons	0	0	803.6	0	0	0	0	0	803.6
NH3	tons	0	0	653.5	0	0	0	0	0	653.5
Nutrients	tons	0	0	81.18	0	0	0	0	0	81.18
BFW Chemicals										
Amine	tons	0	0	0.615	0	0	0	0	0	0.615
Hydrazine	tons	0	0	2.05	0	0	0	0	0	2.05
Na2PO4	tons	0	0	0.205	0	0	0	0	0	0.205
CW Chemicals										
Orthophosphate	tons	0	0	1.599	0	0	0	0	0	1.599
Phosphonate	tons	0	0	0.4756	0	0	0	0	0	0.4756
Polyphosphate	tons	0	0	1.599	0	0	0	0	0	1.599
Silicate	tons	0	0	1.271	0	0	0	0	0	1.271
Zinc	tons	0	0	0.82	0	0	0	0	0	0.82
WWT Chemicals										
Phosphate	tons	0	0	172.2	0	0	0	0	0	172.2
Polymer	tons	0	0	0	0	0	0	0	0	0
Urea	tons	0	0	492	0	0	0	0	0	492

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Table I-8. Fuel Cycle Inventory: E95, Rochester, NY

Emission or Concern	Units	End-Use	E-95 Dist.	E-95 Prodtn.	Fdstk S&T	Aggregate Fdstk	Grass Fdstk	Tree Fdstk	Cane Fdstk	Grand Total
Inputs										
Crude oil	bbls	0	0	0	0	0	0	0	0	0
Diesel	gallons	0	65000	83640	284540	597780	396060	201720	0	1030960
Diesel (No. 6)	gallons	0	0	23000	0	0	0	0	0	23000
Ethanol-10	gallons	0	0	0	0	0	0	0	0	0
Ethanol-95	gallons	0	0	0	0	0	0	0	0	0
Gasoline	gallons	0	0	1453040	0	0	0	0	0	1453040
Insecticides	tons	0	0	0	0	0.656	0.574	0.082	0	0.656
MTBE	gallons	0	0	202000	0	0	0	0	0	202000
Natural gas	mmscf	0	0	9.6	0	0	0	0	0	9.6
Refinery Products	gallons	0	0	0	0	0	0	0	0	0
Water	gallons	0	0	241668760	0	0	0	0	0	241668760
Electricity	kWh	0	13472000	-54060000	0	0	0	0	0	-40588000
Herbicides	tons	0	0	0	0	4.182	2.46	1.722	0	4.182
K2O-Fertilizer	tons	0	0	0	0	1869.6	1763	106.6	0	1869.6
N-Fertilizer	tons	0	0	0	0	2386.2	2025.4	360.8	0	2386.2
P2O5-Fertilizer	tons	0	0	0	0	1279.2	1172.6	106.6	0	1279.2
Antifoam	tons	0	0	16.4	0	0	0	0	0	16.4
CS Liquor	tons	0	0	269.78	0	0	0	0	0	269.78
Glucose	tons	0	0	508.4	0	0	0	0	0	508.4
H2SO4	tons	0	0	4346	0	0	0	0	0	4346
Lime	tons	0	0	3206.2	0	0	0	0	0	3206.2
Limestone	tons	0	0	717.5	0	0	0	0	0	717.5
NH3	tons	0	0	633.5	0	0	0	0	0	633.5
Nutrients	tons	0	0	77.08	0	0	0	0	0	77.08
BFW Chemicals										
Amine	tons	0	0	0.615	0	0	0	0	0	0.615
Hydrazine	tons	0	0	2.05	0	0	0	0	0	2.05
Na2PO4	tons	0	0	0.205	0	0	0	0	0	0.205
CW Chemicals										
Orthophosphate	tons	0	0	1.5416	0	0	0	0	0	1.5416
Phosphonate	tons	0	0	0.4674	0	0	0	0	0	0.4674
Polyphosphate	tons	0	0	1.5416	0	0	0	0	0	1.5416
Silicate	tons	0	0	1.2382	0	0	0	0	0	1.2382
Zinc	tons	0	0	0.738	0	0	0	0	0	0.738
WWT Chemicals										
Phosphate	tons	0	0	191.9	0	0	0	0	0	191.9
Polymer	tons	0	0	0	0	0	0	0	0	0
Urea	tons	0	0	492	0	0	0	0	0	492

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Table I-9. Fuel Cycle Inventory: E95, Portland, OR

Emission or Concern	Units	End-Use	E-95 Dist.	E-95 Prodtn.	Fdstk S&T	Aggregate Fdstk	Grass Fdstk	Tree Fdstk	Cane Fdstk	Grand Total
Inputs										
Crude oil	bbls	0	0	0	0	0	0	0	0	0
Diesel	gallons	0	81000	35018	350740	536050	0	536050	0	1002808
Diesel (No. 6)	gallons	0	0	23000	0	0	0	0	0	23000
Ethanol-10	gallons	0	0	0	0	0	0	0	0	0
Ethanol-95	gallons	0	0	0	0	0	0	0	0	0
Gasoline	gallons	0	0	1258830	0	0	0	0	0	1258830
Insecticides	tons	0	0	0	0	0.213	0	0.213	0	0.213
MTBE	gallons	0	0	202000	0	0	0	0	0	202000
Natural gas	mmscf	0	0	9.6	0	0	0	0	0	9.6
Refinery Products	gallons	0	0	0	0	0	0	0	0	0
Water	gallons	0	0	293939290	0	0	0	0	0	293939290
Electricity	kWh	0	13545000	-1.01E8	0	0	0	0	0	-87141000
Herbicides	tons	0	0	0	0	4.118	0	4.118	0	4.118
K2O-Fertilizer	tons	0	0	0	0	248.5	0	248.5	0	248.5
N-Fertilizer	tons	0	0	0	0	852	0	852	0	852
P2O5-Fertilizer	tons	0	0	0	0	248.5	0	248.5	0	248.5
Antifoam	tons	0	0	20.59	0	0	0	0	0	20.59
CS Liquor	tons	0	0	338.67	0	0	0	0	0	338.67
Glucose	tons	0	0	596.4	0	0	0	0	0	596.4
H2SO4	tons	0	0	3976	0	0	0	0	0	3976
Lime	tons	0	0	2903.9	0	0	0	0	0	2903.9
Limestone	tons	0	0	262.7	0	0	0	0	0	262.7
NH3	tons	0	0	711.4	0	0	0	0	0	711.4
Nutrients	tons	0	0	97.27	0	0	0	0	0	97.27
BFW Chemicals										
Amine	tons	0	0	0.7952	0	0	0	0	0	0.7952
Hydrazine	tons	0	0	2.627	0	0	0	0	0	2.627
Na2PO4	tons	0	0	0.2627	0	0	0	0	0	0.2627
CW Chemicals										
Orthophosphate	tons	0	0	2.0448	0	0	0	0	0	2.0448
Phosphonate	tons	0	0	0.6106	0	0	0	0	0	0.6106
Polyphosphate	tons	0	0	2.0448	0	0	0	0	0	2.0448
Silicate	tons	0	0	1.633	0	0	0	0	0	1.633
Zinc	tons	0	0	0.994	0	0	0	0	0	0.994
WWT Chemicals										
Phosphate	tons	0	0	99.4	0	0	0	0	0	99.4
Polymer	tons	0	0	0	0	0	0	0	0	0
Urea	tons	0	0	284	0	0	0	0	0	284

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Table I-10. Fuel Cycle Inventory: E95, Lincoln, NE

Emission or Concern	Units	End-Use	E-95 Dist.	E-95 Prodtn.	Fdstk S&T	Aggregate Fdstk	Grass Fdstk	Tree Fdstk	Cane Fdstk	Grand Total
Inputs										
Crude oil	bbls	0	0	0	0	0	0	0	0	0
Diesel	gallons	0	92000	194500	166000	650720	650720	0	0	1103220
Diesel (No. 6)	gallons	0	0	23000	0	0	0	0	0	23000
Ethanol-10	gallons	0	0	0	0	0	0	0	0	0
Ethanol-95	gallons	0	0	0	0	0	0	0	0	0
Gasoline	gallons	0	0	1469930	0	0	0	0	0	1469930
Insecticides	tons	0	0	0	0	0.747	0.747	0	0	0.747
MTBE	gallons	0	0	202000	0	0	0	0	0	202000
Natural gas	mmscf	0	0	9.6	0	0	0	0	0	9.6
Refinery Products	gallons	0	0	0	0	0	0	0	0	0
Water	gallons	0	0	226691260	0	0	0	0	0	226691260
Electricity	kWh	0	13375000	-50749000	0	0	0	0	0	-37374000
Herbicides	tons	0	0	0	0	3.652	3.652	0	0	3.652
K2O-Fertilizer	tons	0	0	0	0	2365.5	2365.5	0	0	2365.5
N-Fertilizer	tons	0	0	0	0	2124.8	2124.8	0	0	2124.8
P2O5-Fertilizer	tons	0	0	0	0	1577	1577	0	0	1577
Antifoam	tons	0	0	14.94	0	0	0	0	0	14.94
CS Liquor	tons	0	0	239.04	0	0	0	0	0	239.04
Glucose	tons	0	0	473.1	0	0	0	0	0	473.1
H2SO4	tons	0	0	4399	0	0	0	0	0	4399
Lime	tons	0	0	3245.3	0	0	0	0	0	3245.3
Limestone	tons	0	0	813.4	0	0	0	0	0	813.4
NH3	tons	0	0	592.0	0	0	0	0	0	592.0
Nutrients	tons	0	0	68.89	0	0	0	0	0	68.89
BFW Chemicals										
Amine	tons	0	0	0.5395	0	0	0	0	0	0.5395
Hydrazine	tons	0	0	1.826	0	0	0	0	0	1.826
Na2PO4	tons	0	0	0.1826	0	0	0	0	0	0.1826
CW Chemicals										
Orthophosphate	tons	0	0	1.4525	0	0	0	0	0	1.4525
Phosphonate	tons	0	0	0.4316	0	0	0	0	0	0.4316
Polyphosphate	tons	0	0	1.4525	0	0	0	0	0	1.4525
Silicate	tons	0	0	1.162	0	0	0	0	0	1.162
Zinc	tons	0	0	0.747	0	0	0	0	0	0.747
WWT Chemicals										
Phosphate	tons	0	0	207.5	0	0	0	0	0	207.5
Polymer	tons	0	0	0	0	0	0	0	0	0
Urea	tons	0	0	498	0	0	0	0	0	498

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Allocation Assumptions for Crude Oil
Reformulated Gasoline Fuel Cycle

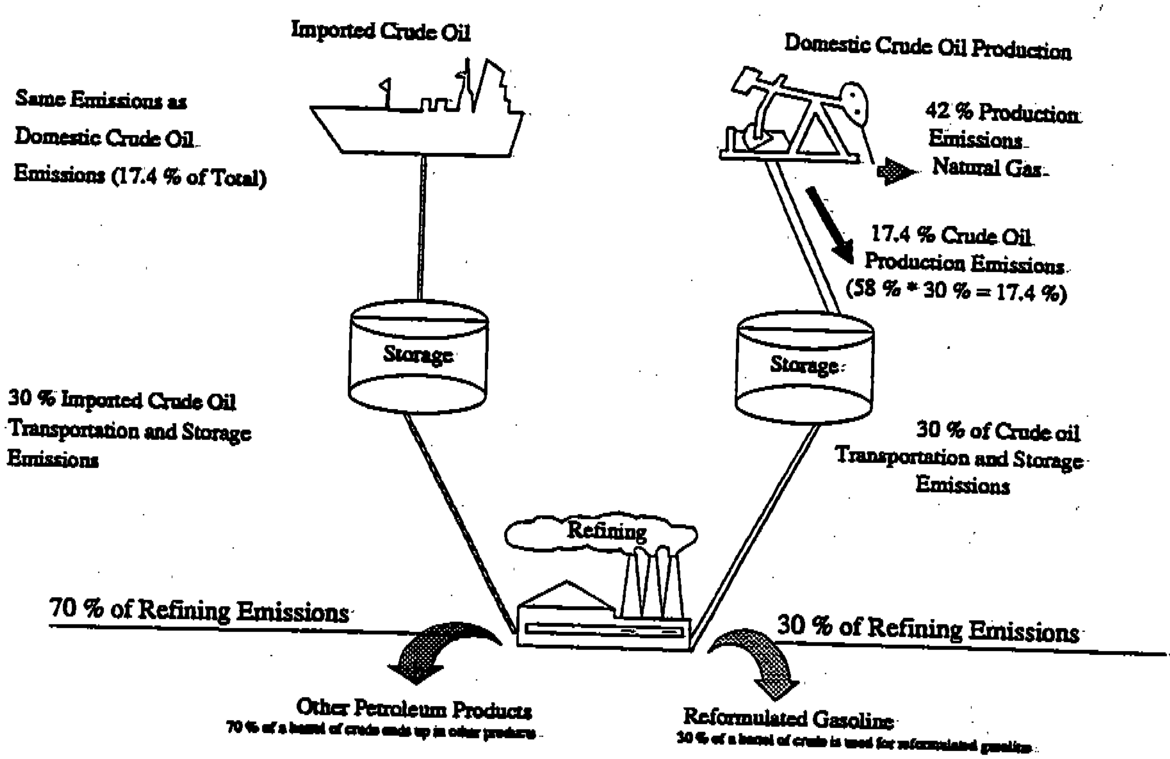

Figure 1. Allocation Schematic for Reformulated Gasoline Fuel Cycles

Four allocations were performed in the E10 basecase (Figure 2). The first eliminated the inputs associated with garbage collection and transportation to transfer stations. While this may not be properly considered an allocation, it is important from the standpoint of accounting for energy inputs. These activities were eliminated from the fuel cycle because they would occur in the absence of a ethanol industry, since waste will always need to be removed from urban areas.

The second allocation is similar to the refinery allocation described above. Metal, glass, and other inorganic materials are separated from the organic materials at the MSW sorting facility. The metals, glass and other inorganics could be sold or transported to landfills. The disposal of the inorganic MSW fraction was not included in the fuel cycle. In addition, the inputs associated with transporting MSW from the transfer stations to the sorting facility and the inputs associated with sorting MSW were divided between the organic fraction and the inorganic fraction of MSW on a dry weight basis. Thus, only 71 percent of the MSW transportation inputs (transportation between transfer stations and sorting plant) and 71 percent of the sorting plant inputs are included in the basecase.

Allocation Assumptions for the
MSW - E10 Fuel Cycle

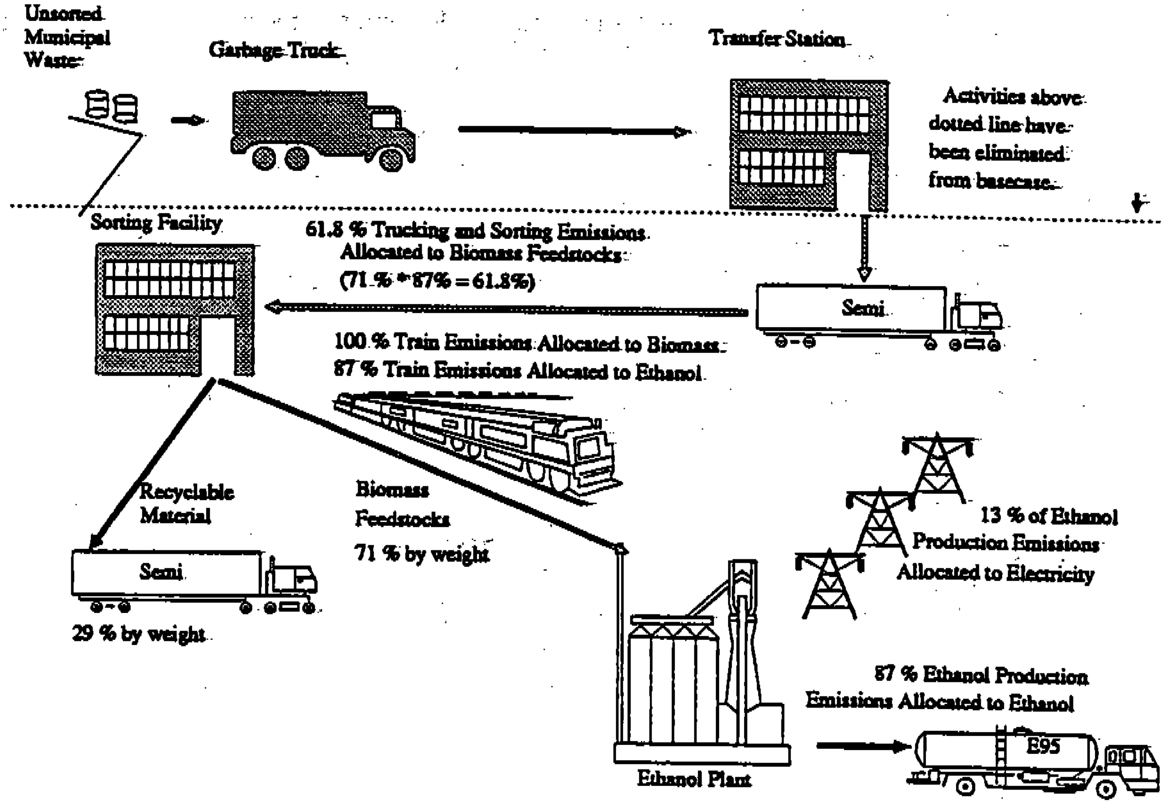

Figure 2. Allocation Schematic for the E10 Fuel Cycle.

The third allocation is also similar to the refinery allocation. Electricity and ethanol are co-products of a conversion facility (see Appendix C, Biomass Conversion). The net electricity output is shown in Table I-4 as a credit in the fuel production stage (net because some electricity consumption is reflected in this stage from the addition of the fuel cycle inputs associated with the gasoline used to denature the ethanol). This credit is NOT reflected in the energy balance because the inputs associated with biomass production, transportation and conversion where allocated between the two products on a Btu basis. The division between ethanol and electricity was calculated as follows:

$$\frac{\text{(LHV ethanol Btu/gal)} * \text{gallons per year per billion miles}}{[\text{(LHV ethanol Btu/gal)} * \text{(gal/yr/billion VMT)}] + [\text{(10,400 Btu/Kwhr)}*\text{(kwhr/yr/billion miles)}]}$$

Therefore, 87 percent of the ethanol production inputs are shown in Table I-4. In addition, only 61.8 percent of the sorting and semi trailer transportation inputs (87 percent of the 71 percent) are shown in Table I-4.

The fourth allocation may not be a proper allocation, but again, it is important from an energy balance standpoint. The energy inputs associated with the 90 percent gasoline contained in E10 are added to the E10 fuel cycle. The additions are made to the stages where gasoline is combined with ethanol. In the fuel production stage, 5 percent gasoline is used to denature ethanol before it leaves the production facility. Thus, the total fuel cycle energy inputs associated with the number of gallons of gasoline used to denature ethanol are added to the fuel production stage in the E10 fuel cycle. Once the E95 reaches its bulk storage facility it is used to dilute gasoline until a ratio of 10 percent ethanol/90 percent gasoline is reached. Once again, the total fuel cycle energy inputs associated with the gallons of gasoline added to produce E10 are added to the E10 fuel cycle in the fuel distribution stage. Thus, some of the energy inputs shown in Table I-4 are energy inputs from the reformulated gasoline fuel cycle (e.g. for the 90 percent of the fuel) and some are associated with ethanol production and use. Table I-11 shows the inputs that are uniquely associated with the ethanol fraction of E10.

Only two allocation processes were applied to the E95 basecases (Figure 3). In the E95 cases, electricity is shown as a negative input in the ethanol production stage. This credit is the amount of electricity produced as a coproduct to the ethanol produced per 1 billion VMT. Because the other inputs have already been allocated between ethanol and electricity products, this credit is ignored in the energy analysis. Biomass production, transportation, storage and conversion inputs were divided between ethanol and electricity. Each of the E95 cases had a unique ratio of ethanol energy to electricity energy outputs depending on the type of biomass material used as a feedstock. Those ratios are shown in Table I-12.

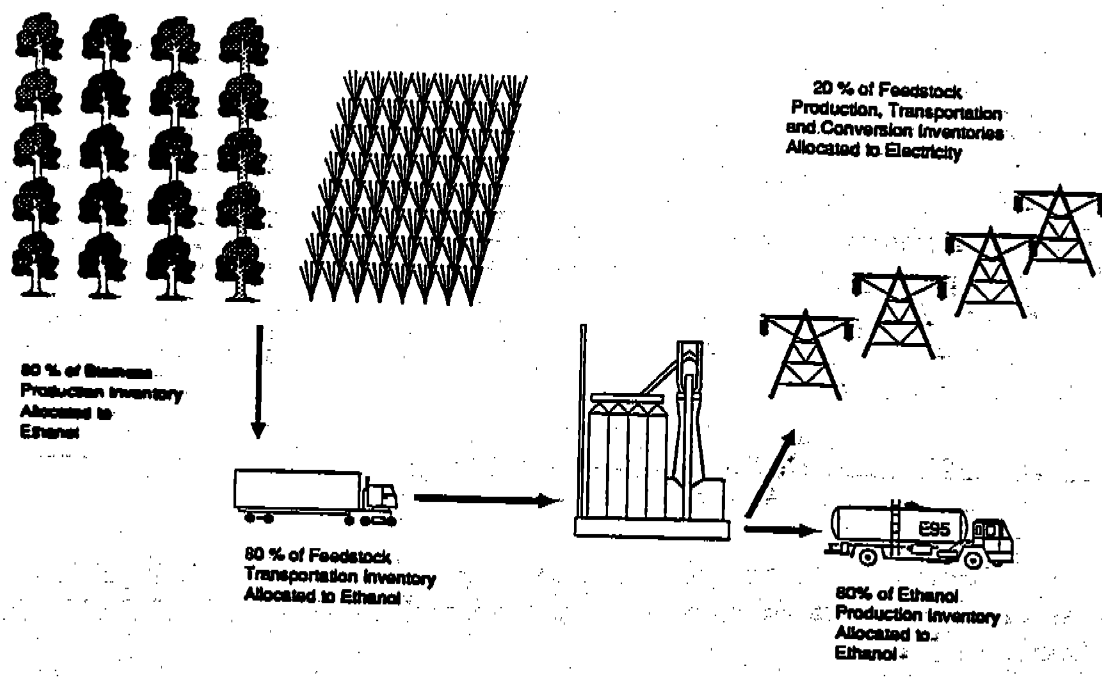

Figure 3. Fuel Cycle Allocations for E95 Basecases.

Table I-11: Fuel Cycle Inventory: E10 without Reformulated Gasoline Fuel Cycle Emissions

Emission or Concern	Units	End-Use	E-95 Dist.	E-95 Prodtn.	MSW Trans	MSW Sort	MSW Collctn	Grand Total
Inputs								
Crude oil	bbls	0	0	0	0	0	0	0
Diesel	gallons	0	32190	4350	16530	6090	18270	77430
Diesel (No. 6)	gallons	0	0	0	0	0	0	0
Ethanol-10	gallons	0	0	0	0	0	0	0
Ethanol-95	gallons	0	0	0	0	0	0	0
Gasoline	gallons	0	25779840	152250	0	0	0	25932090
Insecticides	tons	0	0	0	0	0	0	0
MTBE	gallons	0	0	0	0	0	0	0
Natural gas	mmscf	0	0	0	0	0	0	0
Refinery Products	gallons	0	0	0	0	0	0	0
Water	gallons	0	0	30828450	0	0	0	30828450
Electricity	kWh	0	8333730	-3498000	214020	13040430	0	18090180
Herbicides	tons	0	0	0	0	0	0	0
K2O-Fertilizer	tons	0	0	0	0	0	0	0
N-Fertilizer	tons	0	0	0	0	0	0	0
P2O5-Fertilizer	tons	0	0	0	0	0	0	0
Antifoam	tons	0	0	3.48	0	0	0	3.48
CS Liquor	tons	0	0	57.42	0	0	0	57.42
Glucose	tons	0	0	69.6	0	0	0	69.6
H2SO4	tons	0	0	522	0	0	0	522
Lime	tons	0	0	382.8	0	0	0	382.8
Limestone	tons	0	0	78.3	0	0	0	78.3
NH3	tons	0	0	88.4	0	0	0	88.4
Nutrients	tons	0	0	16.53	0	0	0	16.53
BFW Chemicals		0	0	0	0	0	0	0
Amine	tons	0	0	0.0609	0	0	0	0.0609
Hydrazine	tons	0	0	0.174	0	0	0	0.174
Na2PO4	tons	0	0	0.0174	0	0	0	0.0174
CW Chemicals		0	0	0	0	0	0	0
Orthophosphate	tons	0	0	0.2001	0	0	0	0.2001
Phosphonate	tons	0	0	0.0609	0	0	0	0.0609
Polyphosphate	tons	0	0	0.2001	0	0	0	0.2001
Silicate	tons	0	0	0.1653	0	0	0	0.1653
Zinc	tons	0	0	0.087	0	0	0	0.087
WWT Chemicals		0	0	0	0	0	0	0
Phosphate	tons	0	0	8.7	0	0	0	8.7
Polymer	tons	0	0	0	0	0	0	0
Urea	tons	0	0	0	0	0	0	0

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Table I-12. Ethanol and Electricity Allocation for E95 Fuel Cycles

E95 Basecase	Percent Allocated to Ethanol	Percent Allocated to Electricity
Tifton, GA	83	17
Portland, OR	71	29
Lincoln, NE	83	17
Peoria, IL	82	18
Rochester, NY	82	18
Average	80	20

The second allocation is not an allocation per se but is important from the energy analysis point of view. The total fuel cycle energy used to produce reformulated gasoline is added to the E95 fuel cycles when gasoline is used to denature ethanol in the conversion facility. Therefore, some fraction of the inputs shown in the fuel production stage are the embedded energy of reformulated gasoline production and some are the inputs required to produce enough ethanol to travel 1 billion VMT on E95. The energy inputs uniquely associated with the gasoline used to denature the ethanol are shown in Table I-13.

The embedded energy associated with the manufacture of fertilizers used to produce biomass and convert it into ethanol are not shown in the input Tables I-6 through I-10; however, it is included in the energy analysis. Likewise, the embedded energy associated with the electricity consumed in all of the fuel cycles is shown in the input tables, but is included in the energy analysis.

Calculating Energy Ratios

The process energy balance compares the sum of the purchased energy inputs (direct and embedded) that are consumed during the production of the fuel to the energy content of the fuel produced. The readers should note that the energy required to run the ethanol facility is not purchased energy, because it is a waste product of ethanol production. The waste lignin and other organics produced by the ethanol plant are consumed in the boilers to produce process heat, steam, and electricity (including electricity sold to others). The organic energy required to run the ethanol plant is not included in the process energy balance. This is also true in the reformulated gasoline basecases. The crude oil shrinkage (crude oil and crude oil products that are consumed to produce heat and power in the refinery) is not included as a purchased input. Thus, the process energy balances will tend to underestimate the true process energy requirements.

Table I-13. Fuel Cycle Emissions Associated with 5 Percent Reformulated Gasoline in E95 Cases

Emission or Concern	Units	End-Use	E-95 Dist.	E-95 Prodtn.	Fdstk S&T	Aggregate Fdstk
Inputs						
Crude oil	bbls	0	0	0	0	0
Diesel	gallons	0	0	0	0	0
Diesel (No. 6)	gallons	0	0	2.30E+04	0	0
Ethanol-10	gallons	0	0	0	0	0
Ethanol-95	gallons	0	0	0	0	0
Gasoline	gallons	0	0	0	0	0
Insecticides	tons	0	0	0	0	0
MTBE	gallons	0	0	2.02E+05	0	0
Natural gas	mmscf	0	0	9.6	0	0
Refinery Products	gallons	0	0	0	0	0
Water	gallons	0	0	0	0	0
Electricity	kWh	0	0	8.57E+05	0	0
Herbicides	tons	0	0	0	0	0
K2O-Fertilizer	tons	0	0	0	0	0
N-Fertilizer	tons	0	0	0	0	0
P2O5-Fertilizer	tons	0	0	0	0	0
Antifoam	tons	0	0	0	0	0
CS Liquor	tons	0	0	0	0	0
Glucose	tons	0	0	0	0	0
H2SO4	tons	0	0	0	0	0
Lime	tons	0	0	0	0	0
Limestone	tons	0	0	0	0	0
NH3	tons	0	0	0	0	0
Nutrients	tons	0	0	0	0	0
BFW Chemicals						
Amine	tons	0	0	0	0	0
Hydrazine	tons	0	0	0	0	0
Na2PO4	tons	0	0	0	0	0
CW Chemicals						
Orthophosphate	tons	0	0	0	0	0
Phosphonate	tons	0	0	0	0	0
Polyphosphate	tons	0	0	0	0	0
Silicate	tons	0	0	0	0	0
Zinc	tons	0	0	0	0	0
WWT Chemicals						
Phosphate	tons	0	0	0	0	0
Polymer	tons	0	0	0	0	0
Urea	tons	0	0	0	0	0

Note: These numbers are subject to change as revisions or refinements proceed. These numbers are derived from calcuations shown in the appendices and modified as described in the author's notes and the main body of the report. These values do not necessarily reflect the degree of signficance implied by the number of digits. These numbers are reported as derived in order to enable the interested person to recalculate and thus verify calculations made.

The gasoline that is added to E10 and E95 is not shown; however, the fuel cycle inputs consumed to produce the gasoline (crude oil, diesel #6, electricity) are added in proportion to the number of gallons of reformulated gasoline consumed in the ethanol basecases. The process energy estimates for the ethanol basecases include the process energy required to produce the gasoline that is added to ethanol for denaturing and blending.

The fossil fuel energy balance compares the fossil fuel inputs to the total fuel output. To the extent that the feedstock used to make a fuel is a fossil fuel (e.g., crude oil or MTBE), it is included in the fossil fuel analysis. This measure provides an estimate of how much of our depletable fossil fuel resources are being consumed to produce the fuel output. Crude oil shrinkage that is used for process energy is captured in this measure; however, the waste lignin consumed in the ethonal plant is not because it is not a fossil fuel.

Total energy efficiency includes process energy and the organic and fossil fuel feedstocks, the sum of all of the energy resources required to produce the liquid fuel compared to the energy contained in the liquid fuel produced. Because the total amount of feedstock produced is included and compared to the total energy output of the fuel production stage, this measure captures the efficiency losses that result from consuming feedstocks for process heat, steam, and power in the fuel production stage.

The energy inputs shown in Tables I-3 through I-10 were multiplied by their associated energy values and summed to determine the total amount of energy inputs for each base case and type of energy ratio. This process and the results are shown in Table I-14.

Table I-15 shows the results of the energy analysis without the allocation of coproducts from the fuel production stage. Instead of dividing the biomass production, transportation and conversion inputs between the ethanol and electricity produced, they are reported in total. Similarly, the inputs for crude oil production, transportation, and refining are not allocated between reformulated gasoline and all other refinery products. In the MSW case, the allocation of ethanol and electricity was removed from the sorting, transportation (of MSW from the transfer station to the sorting facility, and of biomass from the sorting facility to the conversion plant), and conversion inputs. As a result, both the fuel output and the inputs that were allocated increased by the same proportion when the allocation was removed because the allocation ratio was based on the energy content of ethanol (or reformulated gasoline) compared to the total output of the fuel production facility (conversion plant or refinery).

DISCUSSION

Process energy ratios include the energy required to operate equipment and the energy embedded in fertilizer and electricity for the four stages of the fuel cycle: feedstock production, feedstock transportation, fuel production, and fuel distribution. The end-use stage is the output since the only operation that occurs in that stage is the combustion of the fuel to provide mobility. Process energy does not include feedstock energy values or fuel additives such as MTBE. As a result,

Table I-14. ENERGY BALANCES FOR FUEL CYCLES FOR BASECASES

	UNITS	BTU/UNIT	PACIFIC NORTHWEST PORTLAND UNITS/ 10^9VMT	MMBTU/ 10^9VMT	SOUTHEAST TIFTON UNITS/ 10^9VMT	MMBTU/ 10^9VMT	GREAT PLAINS LINCOLN UNITS/ 10^9VMT	MMBTU/ 10^9VMT	MIDWEST/ LAKE STATES PEORIA UNITS/ 10^9VMT	MMBTU/ 10^9VMT	NORTHEAST ROCHESTER UNITS/ 10^ 9VMT	MMBTU/ 10^9VMT
FEEDSTOCK PRODUCTION												
DIESEL #2	GAL	128,700	536,050	68,990	498,000	64,093	650,720	83,748	552,680	71,130	597,780	76,934
DIESEL #6	GAL	137,500	0	0	0	0	0	0	0	0	0	0
ELECTRICITY	KWHR	10,400	0	0	0	0	0	0	0	0	0	0
NATURAL GAS	MMSCF	1.00E+09	0	0	0	0	0	0	0	0	0	0
N-FERTILIZER	TONS	50,000,000	852	42,600	1,371	68,550	2,125	106,250	1,402	70,100	2,386	119,300
K2O FERTILIZER	TONS	6,000,000	248	1,488	1,070	6,420	2,366	14,196	1,123	6,738	1,870	11,220
P2O5 FERTILIZER	TONS	6,000,000	248	1,488	747	4,482	1,577	9,462	795	4,770	1,279	7,674
SUBTOTAL				114,566		143,545		213,656		152,738		215,128
FEEDSTOCK TRANSPORT												
DIESEL #2	GAL	128,700	350,740	45,140	253,150	32,580	166,000	21,364	162,360	20,896	284,540	36,620
DIESEL #6	GAL	137,500	0	0	0	0	0	0	0	0	0	0
ELECTRICITY	KWHR	10,400	0	0	0	0	0	0	0	0	0	0
NATURAL GAS	MMSCF	1,00E+09	0	0	0	0	0	0	0	0	0	0
SUBTOTAL				45,140		32,580		21,364		20,896		36,620
FUEL PRODUCTION												
DIESEL #2	GAL	128,700	35,018	4,507	67,157	8,643	194,500	25,032	77,073	9,919	83,640	10,764
DIESEL #6	GAL	137,500	23,000	3,163	23,000	3,163	23,000	3,163	23,000	3,163	23,000	3,163
ELECTRICITY	KWHR	10,400	857,000	8,913	857,000	8,913	857,000	8,913	857,000	8,913	857,000	8,913
NATURAL GAS	MMSCF	1.00E+09	9.6	9,600	9.6	9,600	9.6	9,600	9.6	9,600	9.6	9,600
AMMONIA	TONS	41,176,471	711	29,276	628.4	25,875	592	24,376	653	26,888	633	26,065
UREA	TONS	30,800,000	284	8,747	415	12,782	498	15,338	492	15,154	492	15,154
PHOSPHATE	TONS	6,000,000	99.4	596	182.6	1,096	208	1,248	172	1,032	190	1,140
SUBTOTAL				64,802		70,071		87,670		74,668		74,798
FUEL DISTRIBUTION												
DIESEL #2	GAL	128,700	81000	10,425	99000	12,741	92000	11,840	104000	13,385	65000	8,366
DIESEL #6	GAL	137,500	0	0	0	0	0	0	0	0	0	0
ELECTRICITY	KWHR	10,400	1.350E+07	140,400	1.330E+07	138,320	1.340E+07	139,360	1.330E+07	138,320	1.350E+07	140,400
NATURAL GAS	MMSCF	1.00E+09	0	0	0	0	0	0	0	0	0	0
SUBTOTAL				150,825		151,061		151,200		151,705		148,766
TOTAL CYCLE												
DIESEL #2	GAL	128,700	1,002,808	129,061	917,307	118,057	1,103,220	141,984	896,113	115,330	1,030,960	132,685
DIESEL #6	GAL	137,500	23,000	3,163	23,000	3,163	23,000	3,163	23,000	3,163	23,000	3,163
ELECTRICITY	KWHR	10,400	14,357,000	149,313	14,157,000	147,233	14,257,000	148,273	14,157,000	147,233	14,357,000	149,313
NATURAL GAS	MMSCF	1.00E+09	9.6	9,600	9.6	9,600	9.6	9,600	9.6	9,600	9.6	9,600
N-FERTILIZER	TONS	50,000,000	852	42,600	1,371	68,550	2,125	106,250	1,402	70,100	2,386	119,300
K2O FERTILIZER	TONS	6,000,000	248	1,488	1,070	6,420	2,366	14,196	1,123	6,738	1,870	11,220
P2O5 FERTILIZER	TONS	6,000,000	248	1,488	747	4,482	1,577	9,462	795	4,770	1,279	7,674
AMMONIA	TONS	41,176,471	711	29,276	628	25,875	592	24,376	653	26,888	633	26,065
UREA	TONS	30,800,000	284	8,747	415	12,782	498	15,338	492	15,154	492	15,154
PHOSPHATE	TONS	6,000,000	99	596	183	1,096	208	1,248	172	1,032	190	1,140
TOTAL ENERGY INPUTS (MMBTU)				375,333		397,258		473,891		400,007		475,312
Crude oil inputs	GAL	138,000	1,549,797	213,872	1,549,797	213,872	1,549,797	213,872	1,549,797	213,872	1,549,797	213,872
MTBE	GAL	94,072	202000	19,003	202000	19,003	202000	19,003	202000	19,003	202,000	19,003
Biomass inputs	TONS	15,000,000	277610	4,721,500	298800	4,755,900	353580	5,303,700	307500	4,813,400	315,700	4,936,400
TOTAL ENERGY PRODUCT (MMBTU)			35,400,000	2,751,642	35,400,000	2,751,642	35,400,000	2,751,642	35,400,000	2,751,642	35,400,000	2,751,642
Ratio of inputs/outputs				In/Out		In/Out		In/Out		In/Out		In/Out
FOSSIL FUEL PROCESS ENERGY IN/FUEL OUTPUT				0.14		0.14		0.17		0.15		0.17
FOSSIL FUEL PROCESS AND FEEDSTOCK ENERGY IN AND FUEL OUTPUT				0.22		0.23		0.26		0.23		0.26
TOTAL INPUTS/TOTAL OUTPUTS				1.94		1.96		2.18		1.98		2.05

TABLE I-14 CONTINUED

	UNITS	BTU/UNIT	E95 Averages UNITS/ 10^9VMT	MMBTU/ 10^9VMT	MSW PEORIA UNITS/ 10^9VMT	MMBTU/ 10^9VMT	REFORM GASOLINE 2000 UNITS/ 10^9VMT	MMBTU/ 10^9VMT	REFORM. GASOLINE 2010 UNITS/ 10^9VMT	MMBTU/ 10^9VMT
FEEDSTOCK PRODUCTION										
DIESEL #2	GAL	128,700	567,046	72,979	24,360	3,135	0	0	0	0
DIESEL #6	GAL	137,500	0	0	0	0	0	0	0	0
ELECTRICITY	KWHR	10,400	0	0	1,295,430	13,472	3,710,000	38,584	3,350,000	34,840
NATURAL GAS	MMSCF	1.00E+09	0	0	0	0	0	0	0	0
N-FERTILIZER	TONS	50,000,000	1,627	81,360		0		0		0
K2O FERTILIZER	TONS	6,000,000	1,335	8,012		0		0		0
P2O5 FERTILIZER	TONS	6,000,000	929	5,575		0		0		0
SUBTOTAL				167,926		16,608		38,584		34,840
FEEDSTOCK TRANSPORT										
DIESEL #2	GAL	128,700	243,358	31,320	16,530	2,127	6,000	772	6,000	772
DIESEL #6	GAL	137,500	0	0	0	0	378,000	51,975	354,000	48,675
ELECTRICITY	KWHR	10,400	0	0	214,890	2,235	7,080,000	73,632	6,930,000	72,072
NATURAL GAS	MMSCF	1.00E+09	0	0	0	0	0	0	0	0
SUBTOTAL				31,320		4,362		126,379		121,519
FUEL PRODUCTION										
DIESEL #2	GAL	128,700	91,478	11,773	4,350	560	0	0	0	0
DIESEL #6	GAL	137,500	23,000	3,163	2,000	275	0	0	0	0
ELECTRICITY	KWHR	10,400	857,000	8,913	199,000	2,070	4.520E+06	47,008	3.910E+06	40,664
NATURAL GAS	MMSCF	1.00E+09	9.6	9,600	0.9	900	160	160,000	150	150,000
AMMONIA	TONS	41,176,471	643	26,496	88.4	3,640		0		0
UREA	TONS	30,800,000	436	13,435	0	0		0		0
PHOSPHATE	TONS	6,000,000	170	1,022	8.7	52		0		0
SUBTOTAL			0	74,402		7,497		207,008		190,664
FUEL DISTRIBUTION										
DIESEL #2	GAL	128,700	88,200	11,351	89,000	11,454	50,000	6,435	41,000	5,277
DIESEL #6	GAL	137,500	0	0	397,000	54,588	56,000	7,700	48,000	6,600
ELECTRICITY	KWHR	10,400	13,400,000	139,360	4.217E+07	438,610	2.040E+07	212,160	1.760E+07	183,040
NATURAL GAS	MMSCF	1.00E+09	0	0	139	139,000	0	0	0	0
SUBTOTAL				150,711		643,651		226,295		194,917
TOTAL CYCLE										
DIESEL #2	GAL	128,700	990,082	127,424	134,240	17,277	56,000	7,207	47,000	6,049
DIESEL #6	GAL	137,500	23,000	3,163	399,000	54,863	434,000	59,675	402,000	55,275
ELECTRICITY	KWHR	10,400	14,257,000	148,273	43,883,320	456,387	35,710,000	371,384	31,790,000	330,616
NATURAL GAS	MMSCF	1.00E+09	9.6	9,600	139.9	139,900	160.0	160,000	150.0	150,000
N-FERTILIZER	TONS	50,000,000	1,627	81,360	0	0	0	0	0	0
K2O FERTILIZER	TONS	6,000,000	1,335	8,012	0	0	0	0	0	0
P2O5 FERTILIZER	TONS	6,000,000	929	5,575	0	0	0	0	0	0
AMMONIA	TONS	41,176,471	643	26,496	88	3,640	0	0	0	0
UREA	TONS	30,800,000	436	13,435	0	0	0	0	0	0
PHOSPHATE	TONS	6,000,000	170	1,022	9	52	0	0	0	0
TOTAL ENERGY INPUTS (MMBTU)				424,360		672,118		598,266		541,940
Crude oil inputs	GAL	138,000	1,549,797	213,872	25,704,000	3,547,152	28,056,000	3,871,728	24,612,000	3,396,456
MTBE	GAL	94,072	202,000	19,003	3,300,000	310,438	3,610,000	339,600	3,120,000	293,505
Biomass inputs	TONS	15,000,000	310,638	4,906,180	30,450	481,980	0	0	0	0
TOTAL ENERGY PRODUCT (MMBTU)			35,400,000	2,751,642	33,100,000	3,546,334	32,500,000	3,594,500	28,100,000	3,107,860
Ratio of inputs/outputs				In/Out		In/Out		In/Out		In/Out
FOSSIL FUEL PROCESS ENERGY IN/FUEL OUTPU				0.15		0.19		0.17		0.17
FOSSIL FUEL PROCESS AND FEEDSTOCK ENERGY AND FUEL OUTPUT				0.24		1.28		1.34		1.36
TOTAL INPUTS/TOTAL OUTPUTS				2.02		1.41		1.34		1.36

TABLE I-15: ENERGY BALANCES FOR FUEL CYCLES WITH FUEL PRODUCTION COPRODUCTS

	UNITS	BTU/UNIT	PACIFIC NORTHWEST PORTLAND UNITS/ 10^9VMT	MMBTU/ 10^9VMT	SOUTHEAST TIFTON UNITS/ 10^9VMT	MMBTU/ 10^9VMT	GREAT PLAINS LINCOLN UNITS/ 10^9VMT	MMBTU/ 10^9VMT	MIDWEST/ LAKE STATES PEORIA UNITS/ 10^9VMT	MMBTU/ 10^9VMT	NORTHEAST ROCHESTER UNITS/ 10^9VMT	MMBTU/ 10^9VMT
FEEDSTOCK PRODUCTION												
DIESEL #2	GAL	128,700	755,000	97,169	600,000	77,220	784,000	100,901	674,000	86,744	729,000	93,822
DIESEL #6	GAL	137,500	0	0	0	0	0	0	0	0	0	0
ELECTRICITY	KWHR	10,400	0	0	0	0	0	0	0	0	0	0
NATURAL GAS	MMSCF	1.00E+09	0	0	0	0	0	0	0	0	0	0
N-FERTILIZER	TONS	50,000,000	1200	60,000	1,652	82,590	2,560	128,012	1,710	85,488	2,910	145,488
K2O FERTILIZER	TONS	6,000,000	349	2,096	1,289	7,735	2,851	17,104	1,370	8,217	2,280	13,683
P2O5 FERTILIZER	TONS	6,000,000	349	2,096	900	5,400	1,900	11,400	970	5,817	1,560	9,359
SUBTOTAL				161,360		172,945		257,416		186,266		262,352
FEEDSTOCK TRANSPORT												
DIESEL #2	GAL	128,700	494,000	63,578	305,000	39,254	200,000	25,740	198,000	25,483	347,000	44,659
DIESEL #6	GAL	137,500	0	0	0	0	0	0	0	0	0	0
ELECTRICITY	KWHR	10,400	0	0	0	0	0	0	0	0	0	0
NATURAL GAS	MMSCF	1.00E+09	0	0	0	0	0	0	0	0	0	0
SUBTOTAL				63,578		39,254		25,740		25,483		44,659
FUEL PRODUCTION												
DIESEL #2	GAL	128,700	49,321	6,348	80,912	10,413	234,337	30,159	93,991	12,097	102,000	13,127
DIESEL #6	GAL	137,500	23,000	3,163	23,000	3,163	23,000	3,163	23,000	3,163	23,000	3,163
ELECTRICITY	KWHR	10,400	857,000	8,913	857,000	8,913	857,000	8,913	857,000	8,913	857,000	8,913
NATURAL GAS	MMSCF	1.00E+09	9.6	9,600	9.6	9,600	9.6	9,600	9.6	9,600	9.6	9,600
AMMONIA	TONS	41,176,471	1001	41,234	757	31,175	713	29,369	796	32,791	772	31,786
UREA	TONS	30,800,000	400	12,320	500	15,400	600	18,480	600	18,480	600	18,480
PHOSPHATE	TONS	6,000,000	140	840	220	1,320	251	1,504	210	1,259	232	1,390
SUBTOTAL				82,417		79,984		101,187		86,301		86,459
FUEL DISTRIBUTION												
DIESEL #2	GAL	128,700	81000	10,425	99000	12,741	92000	11,840	104000	13,385	65000	8,366
DIESEL #6	GAL	137,500	0	0	0	0	0	0	0	0	0	0
ELECTRICITY	KWHR	10,400	1.350E+07	140,400	1.330E+07	138,320	1.340E+07	139,360	1.330E+07	138,320	1.350E+07	140,400
NATURAL GAS	MMSCF	1.00E+09	0	0	0	0	0	0	0	0	0	0
SUBTOTAL				150,825		151,061		151,200		151,705		148,766
TOTAL CYCLE												
DIESEL #2	GAL	128,700	1,379,321	177,519	1,084,912	139,628	1,310,337	168,640	1,069,991	137,708	1,243,000	159,974
DIESEL #6	GAL	137,500	23,000	3,163	23,000	3,163	23,000	3,163	23,000	3,163	23,000	3,163
ELECTRICITY	KWHR	10,400	14,357,000	149,313	14,157,000	147,233	14,257,000	148,273	14,157,000	147,233	14,357,000	149,313
NATURAL GAS	MMSCF	1.00E+09	9.6	9,600	9.6	9,600	9.6	9,600	9.6	9,600	9.6	9,600
N-FERTILIZER	TONS	50,000,000	1,200	60,000	1,652	82,590	2,560	128,012	1,710	85,488	2,910	145,488
K2O FERTILIZER	TONS	6,000,000	349	2,096	1,289	7,735	2,851	17,104	1,370	8,217	2,280	13,683
P2O5 FERTILIZER	TONS	6,000,000	349	2,096	900	5,400	1,900	11,400	970	5,817	1,560	9,359
AMMONIA	TONS	41,176,471	1,001	41,234	757	31,175	713	29,369	796	32,791	772	31,786
UREA	TONS	30,800,000	400	12,320	500	15,400	600	18,480	600	18,480	600	18,480
PHOSPHATE	TONS	6,000,000	140	840	220	1,320	251	1,504	210	1,259	232	1,390
TOTAL ENERGY INPUTS	(MMBTU)			458,180		443,244		535,544		449,754		542,235
Crude oil inputs	GAL	138,000	1,549,797	213,872	1,549,797	213,872	1,549,797	213,872	1,549,797	213,872	1,549,797	213,872
MTBE	GAL	94,072	202000	19,003	202000	19,003	202000	19,003	202000	19,003	202000	19,003
Biomass inputs	TONS	15,000,000	391000	6,650,000	360000	5,730,000	426000	6,390,000	375000	5,870,000	385000	6,020,000
FUEL PRODUCTION			35,400,000	2,751,642	35,400,000	2,751,642	35,400,000	2,751,642	35,400,000	2,751,642	35,400,000	2,751,642
COPRODUCT PRODUCTION			101,543,000 (KWHR)	1,056,047	50,203,000 (KWHR)	522,111	51,606,000 (KWHR)	536,702	55,706,000 (KWHR)	579,342	54,917,000 (KWHR)	571,137
Ratio of inputs/outputs				In/Out		In/Out		In/Out		In/Out		In/Out
FOSSIL FUEL PROCESS ENERGY IN/FUEL OUTPUT				0.12		0.14		0.16		0.14		0.16
FOSSIL FUEL PROCESS AND FEEDSTOCK ENERGY IN AND FUEL OUTPUT				0.18		0.21		0.23		0.20		0.23
TOTAL INPUTS/TOTAL OUTPUTS				1.93		1.96		2.18		1.97		2.05

TABLE I-15 CONTINUED

	UNITS	BTU/UNIT	E95 Averages UNITS/ 10^9VMT	MMBTU/ 10^9VMT	MSW PEORIA UNITS/ 10^9VMT	MMBTU/ 10^9VMT	REFORM GASOLINE 2000 UNITS/ 10^9VMT	MMBTU/ 10^9VMT	REFORM. GASOLINE 2010 UNITS/ 10^9VMT	MMBTU/ 10^9VMT
FEEDSTOCK PRODUCTION										
DIESEL #2	GAL	128,700	708400	91171.08	28,000	3,604	0	0	0	0
DIESEL #6	GAL	137,500	0	0	0	0	0	0	0	0
ELECTRICITY	KWHR	10,400	0	0	1,498,900	15,589	1.828E+07	190,069	1.925E+07	200,230
NATURAL GAS	MMSCF	1.00E+09	0	0	0	0	0	0	0	0
N-FERTILIZER	TONS	50,000,000	2,006	100315.60		0		0		0
K2O FERTILIZER	TONS	6,000,000	1,628	9766.8657		0		0		0
P2O5 FERTILIZER	TONS	6,000,000	1,136	6814.2768		0		0		0
SUBTOTAL				208067.82		19,192		190,069		200,230
FEEDSTOCK TRANSPORT										
DIESEL #2	GAL	128,700	308800	39742.56	19,000	2,445	17,143	2,206	20,000	2,574
DIESEL #6	GAL	137,500	0	0	0	0	1,080,000	148,500	1,180,000	162,250
ELECTRICITY	KWHR	10,400	0	0	247,000	2,569	2.023E+07	210,377	2.310E+07	240,240
NATURAL GAS	MMSCF	1.00E+09	0	0	0	0	0	0	0	0
SUBTOTAL				39742.56		5,014		361,083		405,064
FUEL PRODUCTION										
DIESEL #2	GAL	128,700	112,112	14,429	5,000	644	0	0	0	0
DIESEL #6	GAL	137,500	23,000	3,163	2,000	275	0	0	0	0
ELECTRICITY	KWHR	10,400	857,000	8,913	199,000	2,070	1.291E+07	134,309	1.303E+07	135,547
NATURAL GAS	MMSCF	1.00E+09	9.6	9600	0.9	900	457	457,143	500	500,000
AMMONIA	TONS	41,176,471	808	33,271	102	4,184		0		0
UREA	TONS	30,800,000	540	16,632	0	0		0		0
PHOSPHATE	TONS	6,000,000	210	1,262	10	60		0		0
SUBTOTAL			0	87,270		8,132		591,451		635,547
FUEL DISTRIBUTION										
DIESEL #2	GAL	128,700	88,200	11,351	89,000	11,454	50,000	6,435	41,000	5,277
DIESEL #6	GAL	137,500	0	0	397,000	54,588	56,000	7,700	48,000	6,600
ELECTRICITY	KWHR	10,400	13,400,000	139,360	4.217E+07	438,610	2.040E+07	212,160	1.760E+07	183,040
NATURAL GAS	MMSCF	1.00E+09	0	0	139	139,000	0	0	0	0
SUBTOTAL				150,711		643,651		226,295		194,917
TOTAL CYCLE										
DIESEL #2	GAL	128,700	1,217,512	156,694	141,000	18,147	67,143	8,641	61,000	7,851
DIESEL #6	GAL	137,500	23,000	3,163	399,000	54,863	1,136,000	156,200	1,228,000	168,850
ELECTRICITY	KWHR	10,400	14,257,000	148,273	44,118,900	458,837	71,818,719	746,915	72,986,207	759,057
NATURAL GAS	MMSCF	1.00E+09	9.6	9,600	139.9	139,900	457.1	457,143	500.0	500,000
N-FERTILIZER	TONS	50,000,000	2,006	100,316	0	0	0	0	0	0
K2O FERTILIZER	TONS	6,000,000	1,628	9,767	0	0	0	0	0	0
P2O5 FERTILIZER	TONS	6,000,000	1,136	6,814	0	0	0	0	0	0
AMMONIA	TONS	41,176,471	808	33,271	102	4,184	0	0	0	0
UREA	TONS	30,800,000	540	16,632	0	0	0	0	0	0
PHOSPHATE	TONS	6,000,000	210	1,262	10	60	0	0	0	0
TOTAL ENERGY INPUTS	(MMBTU)			485,791		675,990		1,368,899		1,435,757
Crude oil inputs	GAL	138,000	1,549,797	213,872	25,704,000	3,547,152	80,160,000	11,062,080	82,040,000	11,321,520
MTBE	GAL	94,072	202000	19,003	3,300,000	310,438	3,610,000	339,600	3,120,000	293,505
Biomass inputs	TONS	15,000,000	387400	6,132,000	35,000	554,000	0	0	0	0
FUEL PRODUCTION			35,400,000	2,751,642	33,100,000	3,546,334	32,500,000	3,594,500	28,100,000	3,107,860
COPRODUCT PRODUCTION			62,795,000 (KWHR)	653,068	3,498,000 (KWHR)	36,379	ALL OTHER REFINERY PRODUCTS, Btu Equivalents	6,675,500		7,251,673
Ratio of inputs/outputs				In/Out		In/Out		In/Out		In/Out
FOSSIL FUEL PROCESS ENERGY IN/FUEL OUTPU				0.14		0.19		0.13		0.14
FOSSIL FUEL PROCESS AND FEEDSTOCK ENERGY AND FUEL OUTPUT				0.21		1.27		1.24		1.26
TOTAL INPUTS/TOTAL OUTPUTS				2.01		1.42		1.24		1.26

the process energy ratio underestimates the actual processing energy requirements because thebiomass and crude oil consumed in the fuel production stage to produce process heat and steam has not been accounted for.

The E10 fuel cycle consumes slightly more energy inputs than the reformulated gasoline fuel cycle in 2000, mostly because of redundant fuel transportation requirements. E95 fuel cycles are slightly more efficient than reformulated gasoline 2010, consuming fewer Btus of process energy inputs for every Btu of output. There were also a number of interestings results from the examination of energy consumption by processing stage.

Feedstock production is almost three times more energy intensive (Btu of energy consumed per Btu of energy feedstock produced) for both E95 and the ethanol component of E10 than for reformulated gasoline. This is the result of producing a relatively diffuse, low-Btu fuel. Half of the energy required in feedstock production for E95 is used to fuel farm equipment (diesel) and half is embodied in the production of nitrogen fertilizer. Most of the energy used in biomass production in the E10 fuel cycle is electricity to operate the MSW sorting facility. Because ethanol is only 10 percent of the fuel, the processing energy is low compared to the energy required to produce and process crude oil. If MSW was the feedstock for an E95 fuel cycle, the energy consumed in the feedstock production stage would be similar to energy crop production (e.g., approximately ten times higher).

The energy consumed in feedstock transportation is four to five times higher for reformulated gasoline than for ethanol fuels on a basis of Btu of energy consumed per Btu of feedstock moved. Nearly 60 percent of the energy requirements in crude transportation are electricity inputs for pipeline transportation. The remainder is diesel for tanker, barge, rail, and truck transportation. Crude is transported longer distances (average 615 miles) compared with biomass (26 to 48 miles), which offsets any benefits of moving a more condensed energy product.

Crude oil refining is more energy intensive per Btu of final product (reformulated gasoline) than biomass conversion to E95 when only the process energy inputs are considered. Part of this conclusion results from not accounting for internally produced and consumed process energy in either fuel cycle (by-products of refining and ethanol conversion that are combusted for process heat and power).

Almost 85 percent of the energy inputs reported in the E10 distribution stage are the energy consumed in the fuel cycle activities for producing reformulated gasoline, which is blended with E95 in the distribution stage. The remainder is the energy required to transport E95 to the blenders and deliver E10 to local retailers. When the energy required to distribute reformulated gasoline is combined with the energy required to distribute E95 to the bulk facilities and E10 to retail users, total energy consumed in the E10 distribution stage is 45 percent higher than for reformulated gasoline distribution alone.

The E95 fuel cycles consume less energy in the distribution stage compared with the reformulated gasoline fuel cycles because reformulated gasoline distribution is based on national average transportation distances and E95 distribution is based on regional distribution infrastructure patterns.

The second method of calculating an energy ratio provides an insight into the effects of an ethanol fuel industry on our depletable resources. The total impact of consuming fossil fuels is examined by adding the crude feedstocks (and MTBE) to the process energy estimates. This includes the crude feedstocks that are transformed into reformulated gasoline and added to the ethanol fuel cycles in the conversion and distribution stages. Figure 4 provides a breakdown of process energy inputs and outputs by stage, crude oil feedstocks are shown as a separate input.

E10 provides a small benefit compared with reformulated gasoline in 2000 by consuming 4.5 percent fewer Btus of fossil process energy for every Btu of fuel produced. In 2010, only 0.24 Btu of fossil energy is required to produce 1 Btu of E95, whereas 1.36 Btu of fossil energy is required to produce 1 Btu of reformulated gasoline. Clearly, a biomass-ethanol industry could extend our fossil fuel supply over a longer period of time if the ethanol is used as a dedicated fuel to augment or displace future gasoline demand. The energy balance for reformulated gasoline in 2010 shows some improvement over the ratio of the fuel in 2000, but it still requires more fossil energy input than output produced.

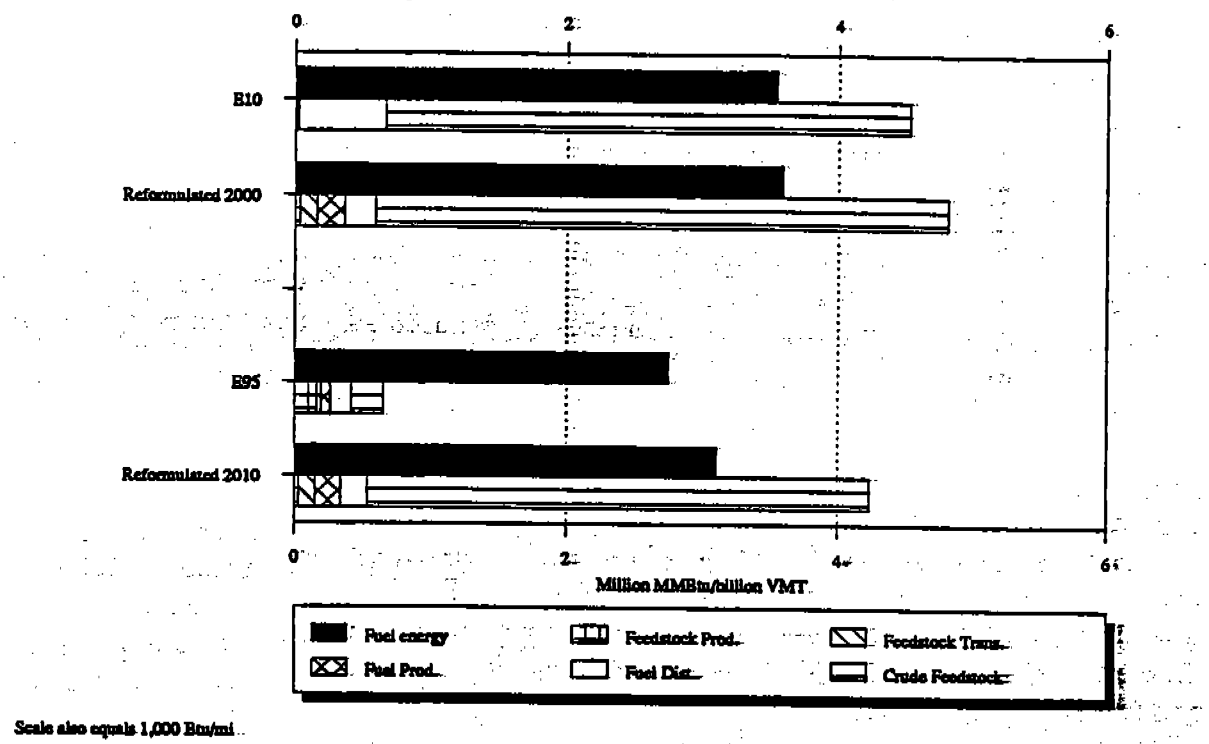
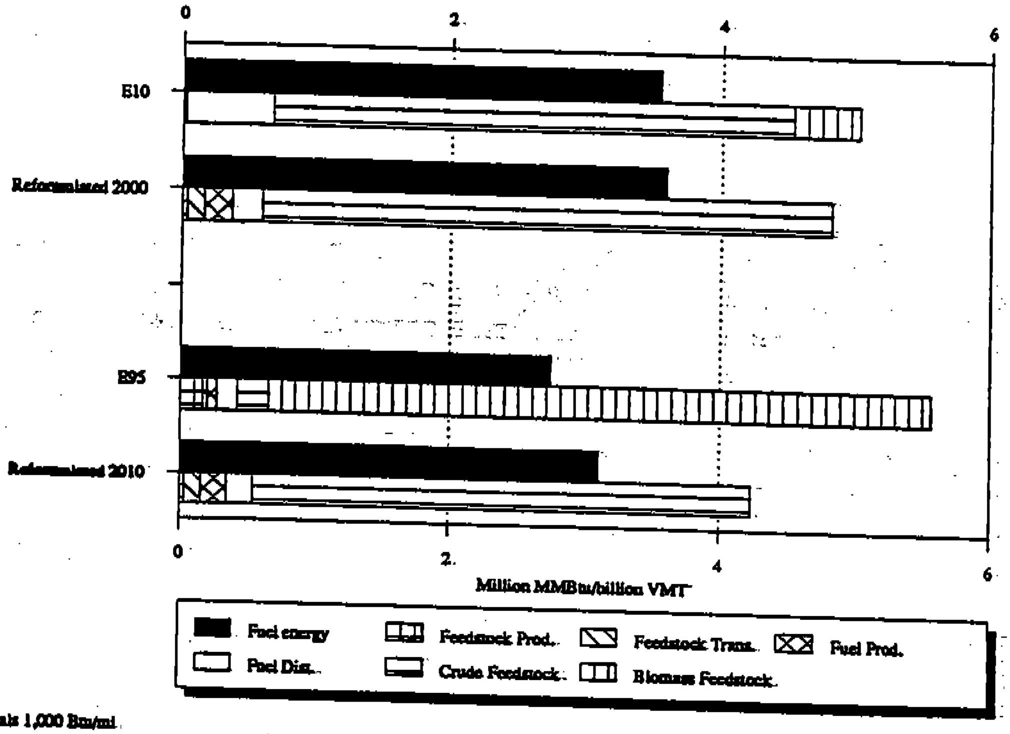


Figure 4: Total energy cycles including crude oil feedstocks.

The third method of calculating energy ratios reflects the sum of all of the inputs (fossil and organic) associated with fuel production. Ethanol fuel cycles appear to be less efficient than reformulated gasoline fuel cycles (Figure 5). Twice as much total energy is used to produce E95 than is contained in the fuel itself; however, 80 percent of that energy is renewable. The lower energy efficiency of the E95 fuel cycle is primarily the result of converting only a fraction of the feedstock into a condensed liquid fuel and using a low-Btu boiler fuel in the ethanol plant.

In Table I-13, only a fraction of total energy inputs are shown in each of the fuel cycles--the portion required to produce, transport, and convert feedstocks into liquid fuel. The allocations discussed eariler have been applied to the scenarios that yielded the energy consumption and production estimates. The excluded energy inputs are transformed into other products, like diesel, electricity, or asphalt. If the electricity produced from the ethanol plant and the other refinery products are included in the fuel cycle analysis, the feedstocks and other inputs are not allocated among by-products. Table I-14 shows the unallocated energy inputs, energy contained in the by-products, and resulting energy ratios. Including all of the feedstock inputs and all of the resulting products does not significantly alter the energy balances reported in Table I-13. Figure 6 depicts the information in Table I-14 graphically.



Scale also equals 1,000 Btu/mi

Figure 5. Total energy cycles including biomass feedstocks.

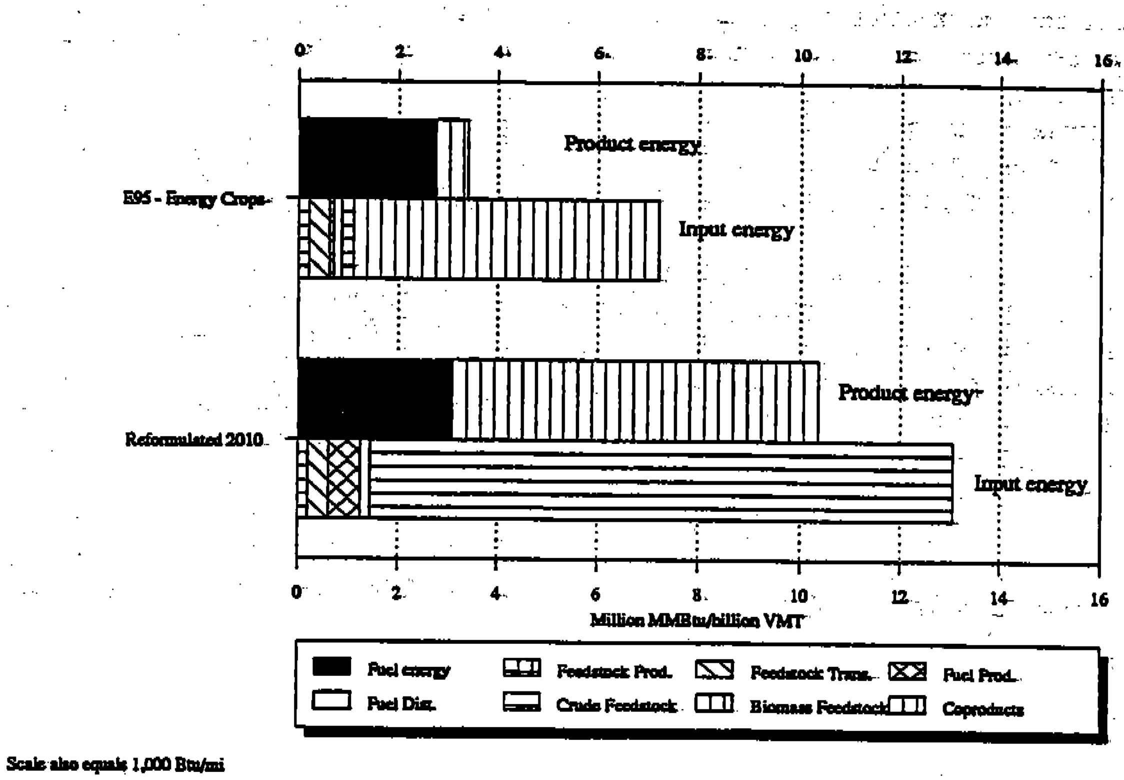


Figure 6. Total energy cycles including coproducts.

Very little change is noticed between the allocated and unallocated energy analyses. The energy ratios for reformulated gasoline fell slightly because fuel transportation became a smaller portion of the total energy input and the inputs and outputs of the other stages increased porportionally when the allocations were removed. As a result of this change, the fossil fuel consumption per Btu of few output is roughly similar for E10 and reformulated gasoline and the process energy requirements for E95 and reformulated gasoline are equal. The previous small advantages that ethanol fuels held over reformulated gasoline disappeared with the exception that the ratio of fossil fuel inputs to fuel output for estimated for reformulated gasoline is still 6 times larger than the ratio estimated for E95.

SUMMARY

There are three major conclusions drawn from this analysis.

- E95 requires only 1 Btu of process energy to produce 7 Btu of fuel. This better than the 6 Btus of reformulated gasoline output per Btu of input and better than the 5 Btu of E10 output per Btu of input.

- Ethanol fuels require less fossil energy per Btu of fuel output compared to reformulated gasoline. Only 1 Btu of fossil energy is required to produce 5 Btu of E95 fuel compared to 1.28 Btu of fossil fuel energy input per Btu of E10 and 1.34 Btu fossil fuel input per Btu of reformulated gasoline.

- The total energy requirements per Btu of fuel produced is higher for ethanol fuels compared to reformulated gasoline because a some of the biomass feedstock is converted to electricity, which has a high conversion ratio (Btu in/Btu out), compared to ethanol production. If a larger fraction of the biomass feedstocks can be converted to ethanol, this ratio could be reduced.

Ethanol fuels are a promising solution to our declining reserves of petroleum, either through augmenting existing fuel supplies by diluting gasoline with ethanol or through developing new fuels to eventually diversify transportation fuels. Although all of the fuels evaluated in this study require more total energy inputs than contained in the fuel output, the difference disappears between E10 and reformlulated gasoline when the renewable nature of some of the energy inputs are considered. Even though it requires 2.02 Btus of energy to produce 1 Btu of E95, 80 percent of the energy inputs are renewable. Thus, E95 production is sustainable in the long term where reformulated gasoline production is limited through resource depletion eventually.

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